ALBERTA

ENERGY RESOURCES CONSERVATION BOATD

DECISIONS

1985

MR. ROY ANDREW APPLICATION FOR HEARING PURSUANT TO SECTION 43 OF THE ENERGY RESOURCES CONSERVATION ACT

ERCB D 85-1 Jan 1985 $ 5

Deals with surface and subsurface location of proposed well, Aberford Summit Gilby 14-34-40-3, and the route of access road into well site.

Discusses environmental impact, adverse effects on farming operations; directional drilling; geology.

SHELL CANADA RESOURCES LIMITED
JUMPING POUND SULPHUR FORMING PROJECT

ERCB D 85-2 Jan 1985 $ 5

Deals with application for approval to construct and operate sulphur forming facilities at Jumping Pound gas plant.

Discusses need for proposed facility; proposed location and alternative sites; area impact and other local concerns.

APPLICATION BY FEDERATED PIPE LINES LTD. FOR A PIPELINE IN THE SWAN HILLS AREA

ERCB D 85-3 Jan 1985 N/C
(Interim Decision)

Application to construct approximately 85 kilometres of 168.3 millimetre diameter pipeline from Swan Hills area to Mitsue field.

Discusses need for pipeline, diameter, whether construction constituted orderly and economic development in public interest, environmental impact. Report contains only Board's conclusions. Full report to be published later.

APPLICATION BY FEDERATED PIPE LINES LTD. TO AMEND PERMIT 21228

ERCB D 85-3 Mar 1985 $ 5

See comments under ERCB D 85-3 (Interim Decision) above.

OCELOT INDUSTRIES LTD. APPROVAL TO MODIFY ITS EXISTING PECO CENTRAL GAS PLANT TO RECOVER ETHANE-PLUS LIQUIDS

ERCB D 85-4 Mar 1985 $ 5

Deals with application by Ocelot Industries Ltd. to install facilities at its existing Peco Central gas processing plant to recover a mixture of ethane and heavier hydrocarbon liquids from natural gas.

Discusses volume of ethane and other natural gas liquids that would be recovered at proposed facility which would be incremental to provincial production; present and future markets for the ethane and other natural gas liquids; cost of ethane recovered at proposed facility; potential impact on existing straddle plant system and on Alberta petrochemical industry; impact on potential for enhanced oil recovery; economic benefits to Alberta; proprietary rights of gas producers; degree of upgrading of resources within Alberta; conservation and environmental aspects of proposed facility.

THOMSON-JENSEN PETROLEUMS LTD. RATEABLE TAKE OF GAS FROM THE ATMORE NISKU A, MCMURRAY B, AND WABISKAW C POOLS

ERCB D 85-5 Jan 1985 $ 5

Deals with application for declaration to equitably distribute gas production among wells in Atmore Nisku A, McMurray B, and Wabiskaw C pools.

Discusses need for a rateable-take order; if a need, method of distributing production; delineation of Atmore Nisku A, McMurray B, and Wabiskaw C pools.

DOME PETROLEUM LIMITED EXPERIMENTAL IN SITU SCHEME LINDBERGH SECTOR

ERCB D 85-6 Feb 1985 $ 5

Deals with application for approval to develop a 16-well cyclic steam experimental project in Cold Lake Wabiskaw-McMurray oil sands deposit in NW quarter of Section 10, Township 56, Range 6, W4M.

Discusses decision made at hearing; reasons for decision.

PANCANADIAN PETROLEUM LIMITED REDUCED WELL SPACING AND CLEANING PLANT LINDBERGH SECTOR

ERCB D 85-7 Feb 1985 $ 5

Deals with application for reduced well spacing in Section 3, Township 56, Range 6, W4M and application to construct and operate a cleaning plant in Legal Subdivision 6 of Section 3.

Discusses need for the reduced spacing and cleaning plant; truck traffic; noise; odours and emissions; impact on ground water; land/soil management; fencing.

DENISON MINES LIMITED ENHANCED RECOVERY MITSUE GILWOOD A POOL

ERCB D 85-8 Feb 1985 $ 5

Deals with application for enhanced recovery of oil by water injection in part of the Mitsue Gilwood A pool.

Discusses suitability of proposed injection well in LSD 14-22-74-6 W5M with respect to pressure maintenance in the area; completion interval of proposed injector; proposed scheme area; request by Coseka Resources Limited to have water injected on behalf of its wells in LSD 2-20-74-5 W5M and LSD 2-26-74-6 W5M.

CONSOLIGAS MANAGEMENT LTD. APPLICATION FOR GAS REMOVAL PERMIT

ERCB D 85-9 May 1985 $ 5

Deals with application for approval of new gas removal permit authorizing removal from Alberta of 214.51 x 10^6 m^3 of gas over a three-year permit term.

Discusses background; gas surplus/Alberta requirements; economic costs and benefits to Alberta; decision.

BRAZEAU RIVER NISKU CARBONATE BANK OPTIMUM DEPLETION INQUIRY AMOCO CANADA PETROLEUM COMPANY LTD.

ERCB D 85-10 Feb 1985 $ 5

Application for approval of a scheme of dry gas cycling in a portion of the Carbonate bank.

Discusses regional geology; areas of pressure communication; hydrocarbon accumulations and reserves; reservoir fluid properties; production/injection configurations; voidage replacement; primary production and operating pressure; cycling rates and facilities; unitization.

SUNCOR INC. RATEABLE TAKE OF GAS ROSEVEAR BEAVERHILL LAKE A POOL

ERCB D 85-11 Mar 1985 $ 5

Deals with application for order to distribute gas production in equitable manner among wells in north Rosevear area, operated by Suncor Inc., and the east leg of the south Rosevear gas unit No. 1, operated by Shell Canada Resources Limited, of the Rosevear Beaverhill Lake A pool.

Discusses delineation of Rosevear Beaverhill Lake A pool; need for rateable-take order; basis for distributing production.

BOW RIVER PIPE LINES LTD. APPLICATION TO CONSTRUCT A CRUDE OIL PIPELINE

ERCB D 85-12 Feb 1985 $ 5

Application to construct approximately 27.8 kilometres of 219.1-millimetre diameter crude oil pipeline and to reverse direction of flow in a portion of its existing crude oil gathering system.

Deals with need for pipeline; ability of revised system to serve the market; economics of serving the market, routing and environmental impact; technical aspects; impact on marketability of Alberta crude oil.

TRANSALTA UTILITIES CORPORATION BOW RIVER HYDRO DEVELOPMENT MODIFICATIONS

ERCB D 85-13 Mar 1985 $ 5

Application by TransAlta Utilities Corporation to increase spill capacities at Bearspaw, Cascade, and Ghost hydro developments.

Discusses background and need to increase spill capacities at these developments; specific modification proposal to increase spill capacity at Bearspaw; proposed construction schedule and effects during construction of proposed modification works at Bearspaw; consequences if no modification is undertaken at Bearspaw.

DOME PETROLEUM LIMITED GAS CYCLING SCHEME, GAS PROCESSING PLANT, SOUR GAS PRODUCTION PIPELINES, FUEL GAS PIPELINES, SOUR GAS INJECTION PIPELINE, SWEET GAS INJECTION PIPELINES - LA GLACE - WEMBLEY AREA

ERCB D 85-14 Feb 1985 $ 5

Discusses need for cycling, suitability of scheme, its effect on oil production; need for processing plant, appropriate size of plant, effect of plant on surrounding area; assessment of public interest of proceeding with deep-cut facility; incremental recovery of ethane-plus liquids; effect on Alberta's existing straddle plants and petrochemical industry; costs and benefits of ethane-plus extraction at Wembley plant; purpose and necessity of the pipelines; pipeline technical and environmental considerations.

AMOCO CANADA PETROLEUM COMPANY LTD. COMMERCIAL OIL SANDS PROJECT (PHASE 1) LINDBERGH SECTOR

ERCB D 85-15 Mar 1985 $ 5

Deals with application for approval of Phase 1 of a 3-phase commercial oil sands project in the Lindbergh sector of the Cold Lake Wabiskaw-McMurray oil sands deposit.

Discusses decision; reasons for decision.

ADDENDUM TO ERCB D 85-15

Mar 1985 N/C

Deals with errata and resulting changes in Sections 1, 4.10 and 6.1 of ERCB D 85-15.

Discusses reason for changes to report.

WILLIAM LUCHYK ENERGY RESOURCES CONSERVATION ACT SECTION 42 REVIEW OF A HUSKY OIL OPERATIONS LTD. REMEDIAL CEMENTING PROGRAM

ERCB D 85-16 Mar 1985 $ 5

Deals with application for review of an approved remedial cementing program to correct a surface casing vent flow from an oil well located in the Wildmere field and operated by Husky Oil Operations Ltd.

Discusses whether applicant's water well being adversely affected by oil well located in LSD 5-18-47-4 W4M; need for remedial program; need for use of acid in remedial program.

ESSO RESOURCES CANADA LIMITED APPLICATION TO PROCEED WITH PHASES V AND VI OF THE COLD LAKE PROJECT

ERCB D 85-17 May 1985 $ 5

Deals with application for approval of details respecting the implementation of Phases V and VI of Esso's Cold Lake project.

Discusses summary of details of Phases V and VI; additional fresh make-up water required during start-up period of Phases V and VI; socio-economic impacts.

CANTERRA ENERGY LTD. BIGORAY NISKU K POOL

ERCB D 85-18 May 1985 $ 5

Deals with application for order designating special drilling spacing unit for 4-10-52-8 W5M well and order establishing off-target penalty factor to be applied to oil production allowable of 02/16-4-52-8 W5M well.

Discusses background; merits of proposed change in target area status of 4-10 well; target area status of 02/16-4 well; need as conservation measure to curtail withdrawal rates from Bigoray Nisku K pool.

APPLICATION BY CANADIAN OCCIDENTAL PETROLEUM LTD. TO CONSTRUCT SOUR GAS, FUEL GAS, PRODUCED WATER, AND SALES GAS PIPELINE SYSTEMS

ERCB D 85-19 May 1985 $ 5

Deals with applications to construct pipelines in Mazeppa area to facilitate recovery of raw gas for processing through Mazeppa gas plant, to transport sweet natural gas for distribution, and to transport produced water to a disposal well.

Discusses need for pipeline connection of gas well located in LSD 11-17-20-28 W4M; need for electromagnetic inspection capability; completion of emergency response plan; pipeline routing through south half of LSD 22-19-28 W4M; construction practices.

ALTANA EXPLORATION COMPANY CAROLINE GAS PROCESSING PLANT

ERCB D 85-20 May 1985 $ 5

Deals with application for approval to increase sulphur dioxide emissions at Caroline gas plant.

Discusses need to increase sulphur dioxide emissions; effects to environment; future development of plant and gas reserves.

ELECTRIC GENERATION EXPANSION 1986-1991 SHEERNESS AND GENESEE POWER PLANTS

ERCB D 85-21 May 1985 $ 5

Discusses electric generating capacity requirements and timing to reliably supply projected electric load of Alberta interconnected electric system for 1986 to 1991; costs and benefits associated with deferral or non-deferral of Sheerness and Genesee units from their currently-approved commissioning dates.

MUNICIPAL DISTRICT OF FOOTHILLS NO. 31 PURSUANT TO SECTION 34 OF THE PIPELINE ACT

ERCB D 85-22 Jun 1985 $ 5

Deals with application to have Canadian Western Natural Gas lower an existing pipeline and remove a valve and vault assembly to accommodate road upgrading of secondary road 549, all at no cost to the municipality.

Discusses decision; reasons for decision.

RANGER OIL LIMITED RATEABLE TAKE OF GAS MAPLE GLEN UPPER MANNVILLE B POOL

ERCB D 85-23 Jun 1985 $ 5

Deals with application for a declaration to set the total withdrawal rate of gas from Maple Glen Upper Mannville B pool and to distribute gas production in an equitable manner among the wells in the pool.

Discusses delineation of pool; need for a rateable-take order.

APPLICATIONS FOR GAS REMOVAL PERMITS NORTHRIDGE PETROLEUM MARKETING, INC., SIGNALTA RESOURCES LIMITED, TRICENTROL OILS LIMITED, LAC MINERALS LTD., GASCAN RESOURCES LTD.

ERCB D 85-24 Jul 1985 $ 5

Deals with applications to remove small volumes of gas from Alberta on a short-term basis.

Discusses applications; submissions of other parties (if any); issues pertinent to applications; Board's decision.

CYANAMID CANADA INC. APPLICATION FOR GAS REMOVAL PERMIT

ERCB D 85-25 Jul 1985 $ 5

Deals with application to remove small volume of gas from Alberta on a short-term basis.

Discusses application; submissions of other parties (if any); issues pertinent to application; Board's decision.

SIMPLOT CHEMICAL COMPANY LTD. APPLICATION FOR GAS REMOVAL PERMIT

ERCB D 85-26 Jul 1985 $ 5

Deals with application to remove small volume of gas from Alberta on a short-term basis.

Discusses application; submissions of other parties (if any); issues pertinent to application; Board's decision.

APPLICATION BY THE IMPERIAL PIPE LINE COMPANY, LIMITED TO CONSTRUCT A PIPELINE AND RELATED FACILITIES AND TO AMEND EXISTING LICENCES

ERCB D 85-27 Jun 1985 $ 5

Deals with applications to construct a pipeline and related facilities between Ellerslie and Sundre, and to increase the maximum operating pressure and to reverse the direction of flow on a line between the Strathcona refinery and Ellerslie, all to transport Cold Lake blended crude bitumen to Sundre.

Discusses reasons for the project; design and capacity of the pipeline system; routing through Section 17-51-24 W4M; efficient use of easements through property of Edmonton Broadcasting Co. Ltd. in SW 1/4-28-51-24 W4M.

APPLICATION FOR GAS REMOVAL PERMITS POCO PETROLEUMS LTD. TRICENTROL OILS LIMITED

ERCB D 85-28 Jul 1985 $ 5

Deals with applications to remove small volumes of gas from Alberta on a short-term basis.

Discusses applications; submissions of other parties (if any); issues pertinent to applications; Board's decision.

APPLICATION FOR GAS REMOVAL PERMIT NORTHRIDGE PETROLEUM MARKETING, INC.

ERCB D 85-29 Jul 1985 $ 5

Deals with application to remove small volume of gas from Alberta on a short-term basis.

Discusses application; submissions from other parties (if any); issues pertinent to application; Board's decision.

ALBERTA GAS CHEMICALS LTD. INDUSTRIAL DEVELOPMENT PERMIT TO MANUFACTURE AMMONIA

ERCB D 85-30 Aug 1985 $ 5

Application for authorization to use 741 million cubic metres of hydrogen as raw material and 36.6 million cubic metres of natural gas as fuel annually, to produce 357 thousand tonnes of ammonia annually; amendment of IDP No. AGC 80-2.

Contains discussions of the availability and efficient use of hydrogen and natural gas in the production of ammonia; views on the marketing of ammonia; views on the impact of the project on the marketing of Alberta-produced ammonia.

WESTCOAST PETROLEUM LTD. GAS PROCESSING PLANT PIPELINE PERMIT 21538

ERCB D 85-31 Jul 1985 $ 5

Deals with application for approval to construct and operate a gas processing plant and pipeline in the Crystal field.

Discusses early conservation of gas; need for two sales gas pipelines; need for two plants; economics of one or two plants and pipelines; environmental impacts; public interest.

ALBERTA POWER LIMITED 144-KV TRANSMISSION LINE CLAIRMONT LAKE - POPLAR HILL

ERCB D 85-32 Jul 1985 $ 5

Deals with application to construct a 144-kV transmission line from Grande Prairie to a new 144/25-kV substation in the Wembley area.

Discusses background and need for facilities; approved route for transmission line and location for the substation.

ANDERSON EXPLORATION LTD. APPROVAL TO MODIFY EXISTING DUNVEGAN GAS PLANT TO RECOVER ETHANE-PLUS LIQUID

ERCB D 85-33 Aug 1985 $ 5

Application for approval to construct facilities to extract ethane and heavier hydrocarbons from natural gas processed in the Dunvegan field.

Discusses amount of ethane that would be recovered by proposed facilities that would be incremental to provincial supply; present and future markets for ethane that would be recovered (supply/demand); comparison of cost of ethane recovered at proposed facility with costs at other facilities; impact on straddle plant system and petrochemical industry; economic impacts on affected parties and on overall public interest; impact on potential for enhanced oil recovery; degree of upgrading of resources; conservation and environmental aspects; Board's findings and conclusions.

MANALTA COAL LTD. CORDEL AREA APPLICATION FOR REPLACEMENT OF MINE LICENCE NO. C 84-18

ERCB D 85-34 Aug 1985 $ 5

Application for replacement licence to continue mining coal for Battle River generating plant.

Discusses status of coal and gas development in area; timing of acquisition of interests and preferential access to resources; reservoir and deliverability forecast for gas well; conflict between coal and gas development; achieving orderly, efficient, and economic development.

APPLICATIONS BY NORTHRIDGE PETROLEUM MARKETING, INC., SIGNALTA RESOURCES LIMITED, AND TRICENTROL OILS LIMITED FOR GAS REMOVAL PERMITS TO EXPORT GAS FROM ALBERTA

ERCB D 85-35 $ 5
GR 85-1

Nov 1985

Deals with applications for three gas removal permits to export a total of 415.6 million m^3 of gas from Alberta for sale to N-Ren Corporation of Ohio, Illinois, U.S.A.

Discusses summaries of the applications; economic costs and benefits analyses; possible effect of the proposed gas removal on certain regulatory authority proceedings in the U.S.A.; possible effect of the proposed sale on renegotiation of "firm-gas" contracts between Canadian suppliers and U.S. buyers; decision.

MURPHY OIL COMPANY LTD. COMMERCIAL OIL SANDS PROJECT (PHASE 1) LINDBERGH SECTOR

ERCB D 85-36 Aug 1985 $ 5

Deals with application for approval of Phase 1 of a commercial oil sands project in Lindbergh sector of the Cold Lake oil sands area.

Discusses pad size and design; size of transportation/utilities right of way; overhead electric power distribution; drilling mud disposal; reclamation; other general concerns.

MAYNARD ENERGY INC. APPLICATION FOR A WELL LICENCE POUCE COUPE FIELD

ERCB D 85-37 Sep 1985 $ 5

Discusses the need for the well; the surface location of the well and access road, and the impact on farming operations.

PUBLIC MEETING TO CONSIDER LANDS INCLUDED IN CITY OF CALGARY SOUR GAS CONSTRAINT AREA

ERCB D 85-38 Sep 1985 $ 5

Discusses ERCB's role in providing information regarding sour gas reserves and facilities to planning authorities; reduction of the "sour gas constraint" area in southeast Calgary.

ALBERTA ENERGY COMPANY LTD. AND COMINCO CHEMICALS AND FERTILIZERS INDUSTRIAL DEVELOPMENT PERMIT TO MANUFACTURE AMMONIA

ERCB D 85-39 Nov 1985 $ 5

Deals with an application for authorization to use 768×10^6 m^3 of hydrogen as raw material and 14.1×10^6 m^3 of natural gas as fuel annually, to produce approximately 350×10^3 tonnes per year of anhydrous ammonia at a new plant to be constructed near Joffre.

Discusses availability and efficient use of feedstock and fuel; marketing of ammonia; economic impacts; plant location; agricultural impact; environmental and social impacts.

APPLICATIONS BY WESTRIDGE PETROLEUM CORP. AND WESTERN COMPRESSION SYSTEMS LTD. FOR APPROVAL OF COMPETING GAS CONSERVATION AND PROCESSING SCHEMES IN THE PREVO-CYGNET AREA

ERCB D 85-40 Nov 1985 $ 5

Deals with each of the competing applications, the size and nature of each plant, and its related gas gathering system.

Discusses the need for gas processing facilities in the Prevo-Cygnet area; the need to ensure efficiency and orderly development of this area; the need for avoiding proliferation of gas plants and the duplication of gas gathering systems in this area; the appropriate location and size of a gas plant to serve this area; effects of the gas plant on the surrounding area.

WESTHILL RESOURCES LTD.
TERMINATION OF ORDER NO. P 38

ERCB D 85-41 Dec 1985

DOME PETROLEUM LIMITED
LINDBERGH COMMERCIAL PROJECT

ERCB D 85-42 Nov. 1985

NOVA, AN ALBERTA CORPORATION
APPLICATION TO CONSTRUCT A GAS PIPELINE IN THE DUHAMEL AREA

ERCB D 85-43 Dec. 1985

DOME PETROLEUM LIMITED
COMMERCIAL IOL SANDS PROJECT AND WATER DISPOSAL SCHEME
COLD LAKE OIL SANDS DEPOSIT PRIMROSE SECTOR

ERCB D 85-44 Dec. 1985

SUNCOR INC.
COMMERCIAL OIL SANDS PROJECT
PRIMROSE SECTOR

ERCB D 85-45 Dec. 1985

EXPLORATORY WELL PROPOSED BY SHELL
FOR JUTLAND (CASTLE RIVER SOUTH) RIVER

MEMORANDUM OF DECISION
PROCEDURES OF MEETING NOV. 1985

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

MR. ROY ANDREW APPLICATION FOR A HEARING PURSUANT TO SECTION 43 OF THE ENERGY RESOURCES CONSERVATION ACT

Decision D 85-1
Application 841177

1 INTRODUCTION

1.1 Background

Aberford Resources Ltd. applied for a licence on 25 September 1984 to drill and produce an oil well in the common oil and gas target area in the southern portion of legal subdivision 14 (Lsd 14) of section 34, township 40, range 3, west of the 5th meridian (see well-site plan attached). The application indicated that the owner of the land surface was Mr. Roy Andrew, the occupant of the land was Mr. Rick King, and that both of them had agreed to the location of the well. The application was approved and the licence for the well, ABERFORD SUMMIT GILBY 14-34-40-3, was issued on 28 September 1984.

By letter dated 23 October 1984, Mr. Bruce Bothwell, solicitor for Mr. Andrew, claimed there had been no agreement as to the location of the well or the access road. Suspension of the well licence was requested and application made for a Board hearing.

On 8 November 1984, the well licence was suspended and the Board directed that the matter be set down for a Board hearing.

1.2 The Hearing

A public hearing of the matter was held on 20 December 1984 at the offices of the Energy Resources Conservation Board (the Board) in Red Deer, Alberta, before Board Members, V. E. Bohme, P.Eng. and C. J. Goodman, P.Eng., and Acting Board Member, H. Antonio, P.Eng.

1.3 Preliminary Matters and Issues

At the beginning of the hearing, Aberford made an application that it be granted local intervener status. The Board did not rule on the application, indicating that local intervener status for Aberford could be determined when an application for costs was submitted to the Board.

The Board notes that Mr. Andrew's submission of 17 December 1984 does not dispute Aberford's right to any hydrocarbons that may underlie the northwest quarter of section 34-40-3 W5M (NW 1/4 of 34) nor did it dispute the need for a well to evaluate and recover those hydrocarbons. The Board therefore considers the issues with respect to this matter to be:

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Mr. Roy Andrew (Mr. Andrew) B. N. Bothwell	R. Andrew R. King
Aberford Resources Ltd. (Aberford) B. K. O'Ferrall	G. DeWulf, P.Eng. N. Armstrong, P.Geop. G. Browne J. Hurst, of Pioneer Land Services P. Watson, P.Geol. of Summit Resources Limited
Energy Resources Conservation Board staff M. J. Bruni G. D. Agnew	

- the subsurface location of the well at the producing formation,
- the surface location of the well, and
- the route of the access road.

2 CONSIDERATION OF THE MATTER

2.1 Views of Mr. Andrew

Mr. Andrew's position was that he preferred not to have a well on his land, but if one were required, the licensed location would create significant impact because of the route of the access road or if an oil spill occurred at the well.

Mr. Andrew indicated that the proposed well would have less impact on agricultural operations conducted on Lsd 14 if it were situated farther north, immediately adjacent to the municipal road or in the extreme northeast corner of Lsd 14 (see well site plan). Both Mr. Andrew and Mr. King were of the view that the licensed location would be more difficult to farm around and, due to its elevation in relation to the surrounding land, could be detrimental to their crops and soil if oil or other toxic fluids spilled and flowed off the well site. Mr. Andrew also asked that if the well were to remain where it had been licensed, the access road be relocated. He preferred a route south along the west side of the fence dividing the northwest and northeast quarter sections to a point east of the proposed well site then directly west to the well site, which would have less impact on existing farming patterns. Mr. King indicated that it would be preferable if the east-west portion of the road approached the well site directly at the well centre rather than along the current crop line bordering the northern edge of the well site. Crop lines, he said, could be adjusted without difficulty and if Aberford were to use less than the entire well site on a permanent basis, he would farm it in order to reduce the number of bends and turns involved in farming around the well.

Mr. Andrew believed that the well could be directionally drilled from his preferred locations although he did not submit any evidence with respect to any additional risk, problems, or costs that would be incurred by Aberford as a result. Mr. Andrew did not submit evidence with respect to any savings in farming costs that could result from relocating the well site.

Mr. Andrew said that he would have accepted the current location of the well, but that the cash settlement offered was not sufficient to compensate for the inconvenience of a well in that location. Mr. Andrew agreed that adverse effects could be compensated for but that he and Aberford had not been able to agree on the amount of compensation.

2.2 Views of Aberford

Aberford stated that the location of the proposed well was determined primarily by the correlation of geological data from nearby wells and geophysical data from a seismic survey. Aberford submitted in evidence a Jurassic Sand (Nordegg) net pay isopach map, a map showing the structure on top of the Jurassic Sand, and a Lea Park/Mississippian isochron map based on seismic. The compiled data, according to Aberford, indicated that the best location to drill for oil in the NW 1/4 of 34 was at shot point 197. This location is also within the common oil/gas target area. Aberford indicated that moving the well farther north or northeast, as suggested by Mr. Andrew, would increase the possibility of encountering the gas cap proven to exist by a well drilled in section 3 to the north. Even if the gas cap was not encountered, Aberford indicated locating closer to the gas cap could result in production from the well having a higher gas/oil ratio (GOR). A high GOR could result in a production penalty being applied to the well.

With respect to the impact on the agricultural operations, Aberford indicated that it would relocate the access road as proposed by Mr. Andrew and emphasized that it had been prepared to do so prior to the hearing, if Mr. Andrew would accept the location of the well.

With respect to the possibility of directionally drilling the well from the alternative surface locations preferred by Mr. Andrew, Aberford indicated that such an undertaking could cost an additional $175 000 and increase the possibility of both drilling and production problems. Aberford stated that if the well was successful, oil storage tanks would be diked as required by the Oil and Gas Conservation Regulations. However, Aberford claimed production would in the future likely be pipelined to a central battery located elsewhere and no permanent oil storage facilities would be located on the well site.

2.3 Views of the Board

The Board finds the geological and geophysical evidence submitted by Aberford to be reasonable and in the absence of other data conclude that Aberford's location is geologically superior to the alternatives suggested by Mr. Andrew and Mr. King. The Board agrees that moving the well either north or northeast substantially increases the risk of either encountering the gas cap or penetrating the oil zone at a point where the GOR would be higher than at the licensed location.

The Board notes, from evidence at the hearing, that the ground elevation variances within the NW 1/4 of 34 are

not great and a spill of fluids at the licensed location would not have a significantly higher impact than at the alternative locations. Given this and the existence of regulations requiring dikes around tanks, the Board concludes the environmental reasons put forth by Mr. Andrew and Mr. King do not outweigh the geological reasons advanced by Aberford.

The Board believes that a well site located anywhere on the NW 1/4 of 34 would cause an increase in the number of turns, bends, and corners that would have to be negotiated by farm machinery. The Board accepts that a slightly lesser impact would result from farming around a well site adjacent to the northern boundary of a field versus farming around the licensed well site with an access road located along a crop line. It does not believe this marginally lower impact is sufficient to offset the riskier geologic position that would result from moving the well location north or east.

The Board is of the view that the additional cost of directional drilling is prohibitive in comparison to the benefits of a slight reduction in the adverse effect on the farming operations.

The Board notes Mr. Andrew's comments that he would have agreed to the present well location if the compensation had been suitable, and therefore has some doubt that the well location was really at issue. The Surface Rights Board has the authority via the Surface Rights Act to consider in determining the amount of compensation payable, "the adverse effect of the area granted to the operator on the remaining land of the owner or occupant ...". The Board has not been made aware of any adverse effects in this situation that cannot be compensated for. It therefore concludes that the dispute between Mr. Andrew and Aberford was more properly a matter the Surface Rights Board could have resolved had the licence not been suspended as a result of Mr. Andrew's allegation that the location was at issue.

The Board notes that the original well licence application, which was approved, was accompanied by a survey plan showing the route of the access road different than that agreed to by the parties at the hearing. The Board therefore believes that if it were to confirm the issuance of the well licence it should also amend the licence by setting out the route of the access road as agreed to by all parties at the hearing.

3 DECISION

The Board is satisfied that the well location is appropriate and that the drilling and production of the well will not cause such adverse effect on either the landowner or the occupant that the licence should be rescinded or the well relocated or directionally drilled.

The licence for the well, ABERFORD SUMMIT GILBY 14-34-40-3, is therefore confirmed, reinstated, and amended by adding the following provision:

> "The access road shall be 15 metres wide and entirely within Lsd 14 of Section 34, Township 40, Range 3, West of the 5th Meridian. It shall enter the Legal Subdivision at the extreme northeast corner and shall go south adjacent and parallel to the eastern boundary of the legal subdivision. At a point directly east of the proposed well the access road shall turn west and run directly west to the well site such that the centre line of the road is 348.0 metres south of the northern boundary of the legal subdivision."

DATED at Calgary, Alberta, on 11 January 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme

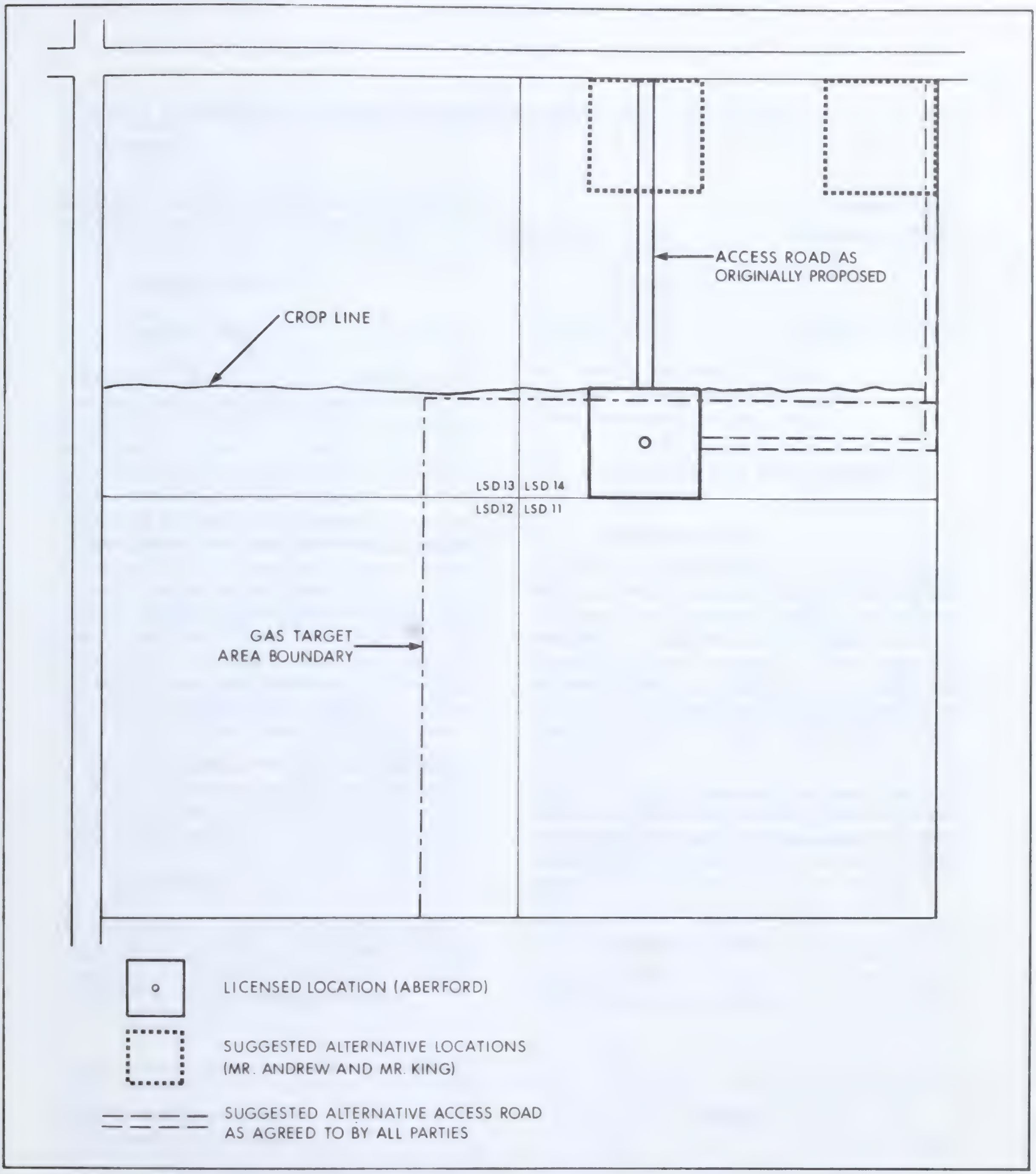
V. E. Bohme, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

H. Antonio

H. Antonio, P.Eng.
Acting Board Member



WELL-SITE PLAN, ABERFORD SUMMIT GILBY 14-34-40-3
NW 1/4 SECTION 34 TWP40 RGE 3 W5M
APPLICATION NO. 841177

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

SHELL CANADA RESOURCES LIMITED JUMPING POUND SULPHUR FORMING PROJECT

Decision D 85-2
Application 841072

1 INTRODUCTION

1.1 The Application

Shell Canada Resources Limited (Shell) applied, pursuant to section 26 of the Oil and Gas Conservation Act, and section 15.050 of the Oil and Gas Conservation Regulations, for approval to construct and operate sulphur forming facilities at its Jumping Pound gas plant located in section 13, township 25, range 5, west of the 5th meridian. The liquid sulphur feedstock for the forming facility would come from gas processing operations at Jumping Pound and from other Shell-owned sulphur production located in the Burnt Timber, Moose Mountain, Whiskey Creek, Okotoks, and Wildcat Hills fields. Liquid sulphur from these fields would be delivered to Jumping Pound by truck. Once formed, the solid sulphur product would be transported from Jumping Pound by existing railway facilities to off-shore market loading terminals located on the west coast.

An intervention opposing the application was filed by Mr. R. A. Copithorne and Mr. C. H. Rhodes, owners of land in the Jumping Pound area. Mr. Rhodes did not appear at the hearing.

1.2 The Hearing

The application was considered at a public hearing in Calgary, Alberta, on 12 December 1984, with V. Millard (Chairman), C. J. Goodman, P.Eng., and R. G. Paterson, P.Eng. (Acting Board Member), sitting.

2 ISSUES

The Board considers the issues regarding the application to be:

- the need for the proposed facility,
- proposed location and alternatives, and
- area impact and other local concerns.

3 THE NEED FOR THE PROPOSED FACILITY

3.1 Applicant's Views

Shell stated that it proposes Rotoform Process technology at Jumping Pound to manufacture a type of sulphur pellet which would have marketing advantages for export sales of sulphur. The applicant said that its scheme would consist of 20 individual Rotoform units with a combined maximum design capacity of 1300 tonnes of sulphur per day. The project would require a $10 million capital investment and provide employment for 32 people during the operation.

Shell stated that the process is operationally and commercially attractive, and would allow Shell to accelerate the reduction of its existing sulphur inventory. The proposal would result in practically no new environmental effects.

3.2 Interveners' Views

R. A. Copithorne did not question the need for the proposed facility, but indicated that he was concerned

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Shell Canada Resources Limited (Shell) D. O. Sabey, Q.C.	L. D. Kelly, P.Eng. B. R. Conn, P.Eng.
R. A. Copithorne C. H. Rhodes	R. A. Copithorne
Energy Resources Conservation Board staff E. P. Moeller, C.E.T. H. R. Hansford	

with the transportation methods for bringing sulphur into the Jumping Pound plant from other areas.

3.3 Board's Views

The Board accepts Shell's evidence as to the economic advantages from marketing sulphur produced by Rotoform technology and the need for the project. It recognizes Mr. Copithorne's concern about the impact the scheme would have on area residents through increased truck transportation. That matter is discussed in Section 5.

4 PROPOSED LOCATION AND ALTERNATIVES

4.1 Applicant's Views

The applicant stated that the Jumping Pound plant was chosen for the Rotoform facility because: Shell is the operator, the plant would contribute 360 tonnes of sulphur per day (t/d), the plant is central to other sources of Shell sulphur, the utilities are available to support the operation, and there is an existing road and rail access. An additional 940 t/d of liquid sulphur would be supplied by truck from other plants, most of which would originate from Burnt Timber.

Shell investigated the feasibility of installing Rotoform units at the Burnt Timber plant as an alternative to trucking 800 t/d to Jumping Pound. It concluded that it was impractical and uneconomic because Burnt Timber has no rail facilities within 25 miles of the plant, and would have to duplicate most of the equipment proposed for Jumping Pound. Shell stated that half (400 t/d) of the sulphur production from Burnt Timber would result from remelting the existing sulphur block over the next 3 to 4 years. After the sulphur block is removed, only the daily liquid sulphur production would be available to the sulphur forming facility.

Shell contended that it is not feasible to transport sulphur from other plants by rail to the Jumping Pound plant because of physical constraints in the Jumping Pound plant site and the fact that Burnt Timber is not served by rail.

Shell also commented on the practicality of constructing Rotoform facilities at the Burnt Timber plant and then transporting the pellets by truck to a rail loading facility. It indicated that the higher capital and operating costs made this alternative impractical. The applicant summarized its view by indicating that the Jumping Pound location was the only economically viable alternative.

4.2 Interveners' Views

R. A. Copithorne said that he opposed the location of the sulphur forming project at Jumping Pound mainly because of the impact it would have on his cattle operation. He said that the continuous flow of truck traffic along the same road he uses periodically for moving up to 300 head of cattle from one location to another would cause him difficulty in managing the cattle herd. He questioned whether it might be feasible and practical for Shell to expand its rail facilities to accommodate transporting sulphur from the other fields by rail to Jumping Pound.

4.3 Board's Views

The Board accepts that the alternative of transporting the liquid sulphur to the Jumping Pound plant by rail rather than by truck is not practical or economic. It also agrees that installing Rotoform facilities at the Burnt Timber plant is not economically sound.

The Board therefore concludes that Jumping Pound is the most suitable location for the Rotoform units.

5 AREA IMPACTS AND OTHER LOCAL CONCERNS

5.1 Applicant's Views

Trucking and Roads

Shell stated that it proposed to deliver up to 940 t/d of liquid sulphur to the Jumping Pound gas plant from other areas. The trucking operation would be continuous for the life of sulphur production at the other gas plants but the supply from Burnt Timber would be reduced by one-half after the sulphur block had been removed. The applicant stated that trucking would result in an annual average of 29 truck-loads of liquid sulphur delivered to the Jumping Pound plant daily and peak deliveries would be 32 trucks per day during the summer months.

Trucks would be confined to paved roads and main access routes to minimize road dust and truck traffic past country residential areas. It stated that the increased truck traffic would necessitate some upgrading of the main plant access road. Shell said that the Jumping Pound plant has been in operation since 1952 and that the road has been upgraded several times in recognition of the traffic associated with plant operations.

It estimated that some 70 vehicles per day use the road now, of which 14 vehicles are trucks carrying propane and sulphur from Jumping Pound to local markets. Shell said that with the proposal to install sulphur forming facilities at Jumping Pound, 7 of the 14 trucks hauling

products out of the plant would be replaced by the trucks hauling sulphur from Burnt Timber and other areas into the plant as the sulphur previously destined for local markets would now be used in the Rotoform process. Shell contended that trucking would be regular but intermittent and would not constitute a significant change in traffic. The applicant stated that it believes that the anticipated traffic can be managed safely and efficiently on the existing road.

Shell also looked at the feasibility of using alternative roads to the plant and found that the proposed route was the most economical and practical. It said that the alternative routes would require considerably more upgrading and higher operating and maintenance costs than the proposed route since none of the alternative roads were paved. Additionally, the applicant said that the road to the east of the plant had more residents along it than the proposed route.

Safety

Shell stated that it considers the existing public road safe and that it has a good safety record associated with its facilities and travel on the road. The applicant would continue discussions with the Municipal District, Alberta Transportation, local residents, and trucking firms to establish appropriate speed limits and design features such as school bus warnings, cattle crossings, and curves in the road. Shell stated that its contract with a trucking firm will highlight safety, would require the trucking firm to implement and adhere to a safety program, and would insist that truckers observe warning and cautionary signs posted along the road to the plant. Shell said that it would investigate a communication network between Shell and the truckers to ensure that radio contact could be made whenever necessary. It would accept responsibility for shutting down its contract trucking operations whenever travel becomes unsafe due to adverse weather conditions. Shell stated that road maintenance is the responsibility of the Municipal District since the road is a public route, however, it would supplement road maintenance with its own equipment as required to facilitate safe truck travel.

Shell said that the trucks would be double-trailer units capable of carrying a 30 tonne load of liquid sulphur. It stated that sulphur in these trucks is not a pressurized commodity, nor explosive, and therefore is not hazardous. Shell has personnel and equipment at the plant to handle any sort of mishap or spillage along the roadway if a truck accidentally slid into a ditch. It has emergency manuals and procedures, training drills, and an experienced group of operators that could quickly respond to such an event. Shell said that it plans to have its contract operator involved in training programs and safety meetings at the plant to prevent mishaps and ensure that safety is a high priority.

Shell said that it would do all that it can to accommodate Mr. Copithorne whenever he moves cattle along the plant roadway. It advised that a person at the plant has been designated as responsible for receiving and responding to any resident complaint received. The applicant said that complaints are reviewed immediately with management at Jumping Pound to determine what appropriate action should be implemented and be acted upon in a responsible manner.

Noise

In response to questioning, Shell stated that it had studied the noise factor associated with the project and that the noise level from the proposed trucks would be similar to the noise level found in a business office. It said that the existing noise and the noise associated with the proposed trucking is intermittent and would be within government standards. The background noise level measured 600 feet from the paved road was 33 1/2 decibels on a 24-hour basis and with existing traffic the noise level was 37 1/2 decibels. It contended that there would be no increase in the noise level with the proposed increase in truck traffic, although Shell admitted that the intermittent noise would occur more often as the number of vehicles increased.

Odours

Shell stated that the sulphur forming scheme is clean and there would be neglible impact in terms of air quality standards. The applicant stated that it did not anticipate any odours from the facility, however, it agreed that there might be some very minor localized odour during the off-loading of liquid sulphur from trucks when the hatch is open so that the sulphur can be drained.

5.1 Interveners' Views

Mr. Copithorne stated that his major concern with the proposed scheme is the increased truck traffic and its serious impact on his cattle operation. At the present time the road right of way is used to move cattle between pastures which is usually done on weekends when traffic is minimal. However, this period of low traffic volume would not exist with proposed week-long sulphur hauling and truck intervals of one every 20 minutes. Mr. Copithorne indicated that he was willing to discuss with Shell procedures for the movement of cattle.

5.3 Board's Views

The Board agrees with the applicant that air and water quality impacts would be negligible and that emissions

and water requirements are accommodated by existing approvals.

The proposed route is the most suitable for transporting sulphur to the Jumping Pound plant considering economics and impact on the minimal number of residents.

The increase of some 30 round trips per day is considered substantial, however, the Board understands that the road was originally built as a municipal road system but later classified as an industrial access road for the Jumping Pound plant when it was built in about 1952. The Board concludes that some 70 vehicles per day currently use the road but 7 carry sulphur from the plant to local markets and would no longer be required under the proposed scheme. Shell would contract for about 8 additional double-trailer units to carry out some 30 round trips per day and the total road use by the plant on weekdays would be about 90 vehicle trips. After 4 years, the Burnt Timber deliveries would be reduced by some 13 deliveries per day and, unless Shell found another source of sulphur to keep the new process operating at full capacity, the vehicle traffic on the road would be reduced to about 80 per day.

The Board acknowledges Mr. Copithorne's concerns on increased traffic volumes interfering with cattle operations but notes the willingness of the applicant and intervener to develop procedures to accommodate the necessary movement of cattle.

Considering the issue of safety in the transportation of liquid sulphur, the Board recognizes Shell for its acceptance of a responsibility for control of contracted hauling, its commitment to work with the Municipal District and Alberta Transportation to improve safety, and to develop, with input from the local residents, a code of conduct for truck operators.

6 DECISION

Having considered the evidence of Shell and Mr. Copithorne, the Board concludes that the proposed sulphur forming project at Jumping Pound is reasonable and in the overall public interest. It would be in accordance with existing regulations and standards and would have minimal new impact.

The Board will issue its approval for the proposed scheme subject to approval of the Minister of Environment with respect to environmental matters and also subject to the following additional conditions to which Shell agreed:

- Shell work with residents, landowners, and trucking firms to develop a code of conduct for truckers delivering sulphur to the Jumping Pound plant,
- all of the personnel contracted by Shell to transport sulphur by truck to Jumping Pound be included in a safety training program to ensure that safety is a high priority on an on-going basis, and
- that the applicant provide information to area residents about its truck safety program and schedules, and from time to time schedule liquid sulphur deliveries so as to permit Mr. Copithorne to move his cattle as required.

DATED in Calgary, Alberta, on 9 January 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

R. G. Paterson

R. G. Paterson, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY FEDERATED PIPE LINES LTD. FOR A PIPELINE IN THE SWAN HILLS AREA

Interim Decision D 85-3
Application 841279

At a public hearing held in the Board's Calgary offices on 11 January 1985 the Board considered an application by Federated Pipe Lines Ltd. (Federated) to construct approximately 85 km of 168.3-mm diameter pipeline from the Swan Hills area to the Mitsue Field.

The Board considers the issues to be

1. The need for the pipeline

2. The size of the pipeline

3. The orderly and economic development in the public interest of pipeline facilities

4. The impact on the environment.

The Board concludes that

1. Federated has established a need for the pipeline

2. The use of a 168.3-mm diameter pipeline is justified

3. The existing 114.3-mm diameter pipeline in the area, operated by Amoco Canada Petroleum Company Ltd., will need modification and possibly looping to handle the predicted volumes. Chevron Canada Resources Limited and its working interest partners in the Mitsue Gilwood Unit No. 1 have agreed to a financial arrangement regarding the proposed pipeline. The existence of a second pipeline in the area will give flexibility of miscible flood liquid supply now and flexibility of transportation elsewhere when the liquids are recovered. The Board therefore considers the proposed pipeline to constitute orderly and economic development in the public interest

4. The Board considers that the short-term environmental disturbance due to pipeline construction is acceptable and that the long-term environmental impact will be negligible.

Therefore the Board will issue the necessary amendment to Permit No. 21228 for the construction of the subject pipeline, but not for the pump station at 9-24-66-10 W5.

A full report containing the reasons for the Board's decision will be issued in due course.

DATED at Calgary, Alberta, on 14 January 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.,
Board Member

C. J. Goodman, P.Eng.,
Board Member

G. A. Warne, P.Eng.,
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY FEDERATED PIPE LINES LTD. TO AMEND PERMIT 21228

Decision D 85-3
Application 841279

1 THE APPLICATION

Federated Pipe Lines Ltd. (Federated) submitted an application to amend an existing permit to enable it to construct approximately 85 km of 168.3-mm diameter pipeline from the Swan Hills area to the Mitsue Field as indicated in the figure. The proposed pipeline is an extension of a pipeline carrying natural gas liquids from Fort Saskatchewan to the Swan Hills area, and would supply natural gas liquids to a miscible-flood project in the Mitsue Field.

2 THE HEARING AND DECISION

The application was considered at a public hearing in Calgary on 11 January 1985 with V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and G. A. Warne, P.Eng., sitting.

Participants at the hearing are identified in the attached table.

On 14 January 1985, the Board issued Interim Decision D 85-3 granting the applied-for amendment to Permit 21228.

3 THE ISSUES

The Board considers the issues to be

(a) the need for the pipeline
(b) the size of the pipeline
(c) the orderly and economic development in the public interest of pipeline facilities, and
(d) the impact on the environment

4 NEED

4.1 Views of Federated

Federated stated that the need for the pipeline is based upon an agreement reached with Chevron Canada Resources Ltd. (Chevron) to provide transportation of natural gas liquids (ethane, propane, and heavier hydrocarbon liquids) to be used at Chevron's approved miscible-flood project at the Mitsue Gilwood Unit 1. The partners in the flood scheme have miscible-flood liquids available at Fort Saskatchewan and Federated argued that, as these liquids would be transported to the Swan Hills area by its existing pipeline, an extension of the existing system had the advantage of providing a fully-integrated system from the source to the flood project. Federated considered the proposed extension to be a necessary adjunct to the flood project, and indicated that it could serve other flood schemes in the general area.

Federated stated that the projected requirements for miscible-flood liquids provided by Chevron are

1985	835 m^3/day	Mitsue Phase 1
1986	1196 m^3/day	Mitsue Phases 1 and 2
1987	1565 m^3/day	Mitsue Phases 1, 2, and 3

with decreasing amounts thereafter.

4.2 Views of the Interveners

Amoco Canada Petroleum Company Ltd. (Amoco) contested the need for the proposed pipeline on the basis that a pipeline suitable for the transportation of miscible-flood liquids in the area already exists. Amoco stated that it operates a 114.3-mm diameter pipeline, called the Mitswan pipeline, which is currently transporting natural gas liquids from Mitsue to Swan Hills. However, an application to reverse the flow and increase the maximum operating pressure had been filed with the Board. With these modifications in place, its pipeline would be capable of transporting volumes in excess of those required by Chevron for the first two phases of the Mitsue Gilwood flood scheme. Amoco stated that the addition of a pump station on its pipeline would accommodate Phase 3 volumes also.

Chevron, as operator of the Mitsue Gilwood Unit, intervened in support of the application by Federated. It confirmed that a minimum of 84 per cent of the working interest partners in the Mitsue Gilwood flood scheme had approved the contract arrangements made with Federated, and that the group had rejected a similar proposal made by Amoco.

Chevron also projected volume requirements for the Nipisi flood scheme phases 2 and 3 showing a maximum requirement in 1988 for Mitsue and Nipisi of 3178 m^3/day.

Dome Petroleum Limited (Dome), which owns 50 per cent of the Mitswan pipeline, supported the contention of Amoco that there is no need for a new pipeline, because the existing pipeline is capable of transporting the required volumes.

Esso Resources Canada Limited (Esso), a partner with Chevron in the Mitsue Gilwood flood scheme and with Amoco in the Nipisi flood scheme, also intervened in support of the Federated application. It stated that the reversal of the Mitswan pipeline would be adequate only as a temporary measure and that the need for another pipeline is inevitable. Esso had participated in Chevron's agreement with Federated and supported Federated's application.

Home Oil Company Limited (Home) also intervened in support of the Federated application. It submitted that Amoco's proposal was inadequate and pointed out that Amoco's transportation proposal to the Mitsue working interest partners had been the subject of lengthy negotiations and was rejected by the group. Home suggested that if the Federated application were not approved, a delay in implementation of the Mitsue flood scheme could result.

4.3 Views of the Board

The Board acknowledges that the existing Amoco pipeline could accommodate the near-term miscible-flood liquids transportation requirements for the Nipisi and Mitsue flood schemes if it were modified to reverse the flow. In the longer term, the Amoco pipeline would require further modification and perhaps looping, and would be working at or near capacity. It therefore leaves little room for flexibility of supply to the flood schemes. The Board believes that a second pipeline is needed to ensure both flexibility of supply and flexibility of transportation from the area when the miscible-flood fluids are recovered from the reservoirs.

The Board notes that of the two competitive bids for the transportation contract, the Mitsue working interest owners preferred the Federated proposal.

5 THE SIZE OF THE PIPELINE

5.1 Views of Federated

Given that Chevron required approximately 1550 m^3 of miscible-flood liquids per day, Federated calculated that a 114.3-mm diameter pipeline would be a suitable size provided a pump station was installed at Swan Hills. It estimated the cost of such a pipeline and pump station at $5 020 000. However, Federated also calculated that a 168.3-mm diameter pipeline without an extra pump station could transport the same volumes at a capital outlay of $5 150 000. Federated pointed out that avoiding the addition of a pump station would result in savings in energy and in maintenance costs, and that the larger line would be adequate to serve the needs of any other miscible-flood scheme which may be developed in the area.

5.2 Views of the Interveners

Amoco presented a number of scenarios to show that, even with all phases of Mitsue and Nipisi miscible floods approved and operating, Federated's proposed 168.3-mm diameter pipeline would operate at a maximum of 44 per cent of its capacity, and therefore would be under-utilized.

Chevron stated that in projecting the needs for the whole area it considered the Federated proposal for a 168.3-mm diameter pipeline adequate and necessary over the long term.

Esso considered the 168.3-mm diameter pipeline would best suit its needs as a participant in both the Mitsue and Nipisi miscible-flood schemes.

5.3 Views of the Board

The Board is satisfied that construction of a 168.3-mm diameter pipeline, as proposed by Federated, is prudent, considering the minimal difference in costs over a 114.3-mm diameter line and that pumping requirements would be minimized.

6 ORDERLY AND ECONOMIC DEVELOPMENT

6.1 Views of Federated

Federated argued that the construction of a pipeline to satisfy the requirements of both the Mitsue and Nipisi miscible-flood schemes is an orderly development. It pointed out that the Amoco Mitswan line was not capable of transporting the long-term requirements of both schemes and that another pipeline would inevitably have to be built.

Federated stated that the working interest owners in the Mitsue Gilwood Unit had considered the alternatives of Amoco and Federated, and preferred Federated's proposal. Therefore its proposal was certainly in the economic interest of the Mitsue group, and because construction will take place at a time when capital projects are scarce, it would be in the overall economic interest of the Province of Alberta.

6.2 Views of the Interveners

Amoco conceded that it could operate its pipeline economically even if the Federated line was approved,

but contended that part of the cost of Federated's proposal had been allotted to the cost of service of Federated's Swan Hills distribution system, and the cost of moving liquids in the existing system would therefore rise. It submitted that this would in turn increase the amounts paid by the Alberta government in miscible-flood incentive payments.

Chevron pointed out that Amoco had not given any assurances that it would make capacity available to all shippers in the Mitsue group when the miscible-flood liquids are recovered, unless the producers sell the liquids to Amoco or Dome. Chevron found this to be unacceptable, and contrasted this with the Federated proposal wherein no such conditions are imposed. It therefore concluded that the Federated proposal was more in the interest of the Mitsue group, and, ultimately, more in the public interest.

Dome submitted that the Amoco alternative of using the existing Mitswan pipeline was a more cost-effective method of transporting the miscible-flood liquids, and therefore, that the Federated proposal was not in the public interest.

Esso stated that it had compared the Amoco and Federated proposals for shipment of miscible-flood liquids and although both involved similar cost, it considered the reversal of the Mitswan pipeline to be a short-term solution to the transportation problem. As a second pipeline would have to be built anyway, Esso preferred the Federated line to allow flexibility to change the volumes of miscible-flood liquids as requirements dictate. The Federated scheme would enable Esso to assure itself of shipment of recovered liquids when they are produced.

Home also pointed out that the Federated proposal was that preferred, on the basis of economics, by the Mitsue group and that, if the Federated application were denied, Amoco would have a monopoly in the area. As the Federated proposal was an extension of the main line, economies in metering and administrative costs would result. Home also supported the concept of greater flexibility of transportion of recovered liquids.

6.3 Views of the Board

Using the pipeline capacities quoted by Amoco and the volume requirements proposed by Chevron, the Board finds that a second pipeline will probably be needed within a 2- to 3-year period. Considering the 5-year projected requirements of miscible-flood liquids, the Board is satisfied that the proposed pipeline is an orderly development in the public interest.

With respect to the economic aspect, the Board finds that the construction of a pipeline now would be in the public interest given the current depressed level of activity in the pipeline construction industry. The Board views the difference in costs between the Federated proposal and the possible Amoco looped pipeline to be inconsequential.

7 THE ENVIRONMENTAL IMPACT

7.1 Views of Federated

Federated described the route as one which partly followed existing seismic lines and pipelines, and for 60 per cent of its length closely parallelled an existing Alberta Power Limited electrical powerline. An agreement had been reached with Alberta Power Limited to utilize part of its right of way for construction purposes. A geotechnical survey showed that slight divergences from the powerline alignment were necessary to cross several watercourses, but overall the amount of tree cutting had been minimized. Federated proposed several mitigative measures to minimize any negative impact on the environment including winter construction, physical breaks in pipeline construction to allow passage of wildlife, and the crossing of watercourses within 24 hours. With these mitigative measures, Federated argued that the overall environmental impact would be low.

7.2 Views of the Interveners

Amoco contended that, compared to its proposed flow reversal on the Mitswan pipeline, the Federated proposal would have greater environmental impact, but did not suggest that the impact would be major.

7.3 Views of the Board

Provided the mitigative measures proposed by Federated are applied, the Board is satisfied that environmental disturbance due to construction activities will be minor and that the long-term impact on the environment will be of no consequence.

8 CONFIRMATION OF DECISION

The Board considers Federated Pipe Lines Ltd.'s proposed pipeline to be a logical extension of Federated's existing system, and that flexibility and efficiency of operation are inherent in the proposal. The Board accepts that, if a second line is not built, the existing Amoco Mitswan pipeline would eventually require looping and the economies attributed to the short-term reversal of flow would not extend to the long term.

The Board therefore approved the application to amend Permit 21228 in its Interim Decision D 85-3, but did not approve the addition of a pump station.

DATED at Calgary, Alberta, on 26 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

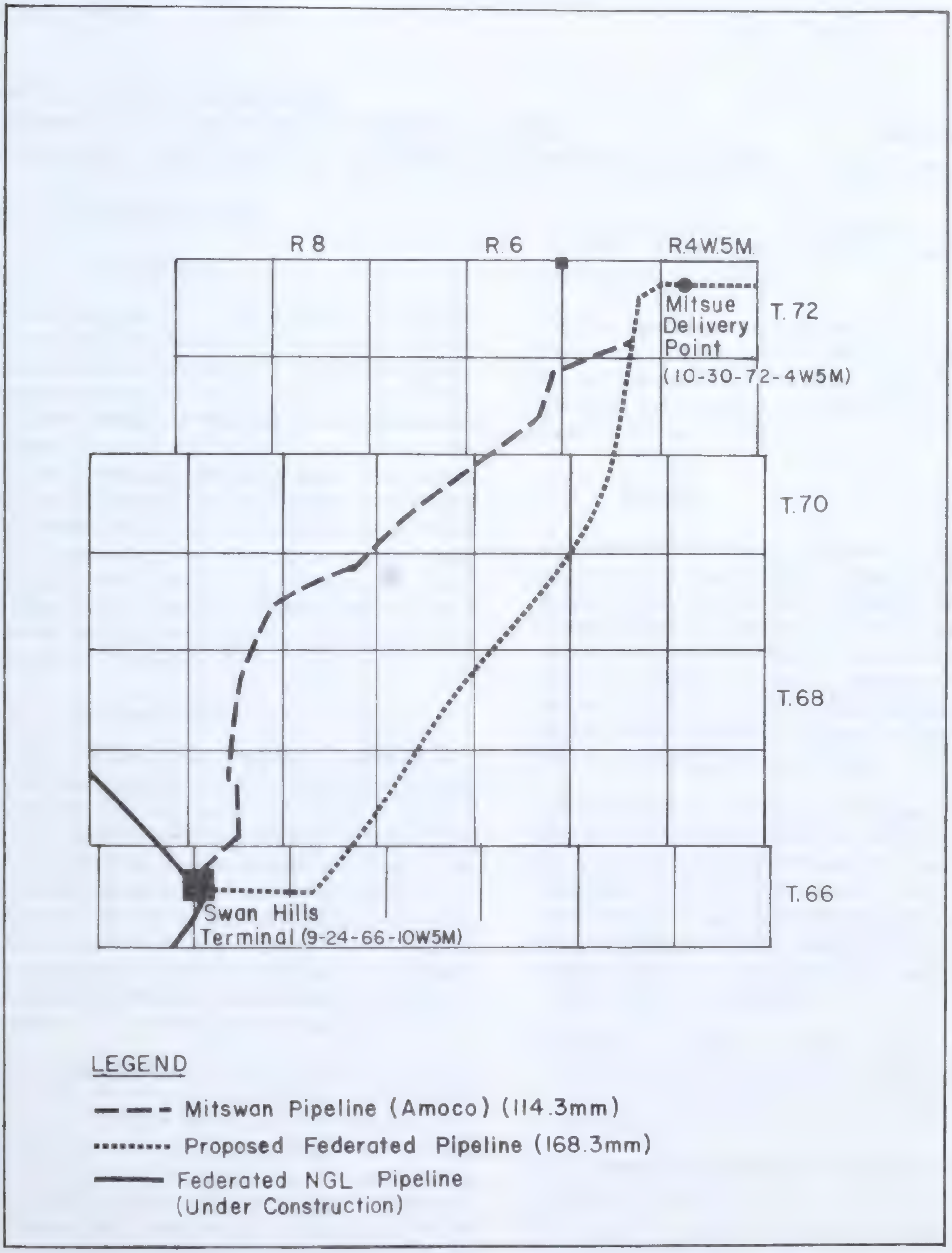
V. E. Bohme, P.Eng.
Board Member

C. J. Goodman
C. J. Goodman, P.Eng.
Board Member

G. A. Warne
G. A. Warne, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Federated Pipe Lines Ltd. (Federated) R. M. Perrin H. L. Simonds	R. C. Osborne, P.Eng. B. Singleton, P.Eng. S. J. Stefanewski D. F. Mutrie of Mutrie-Wishart Environmental Consultants M. Stepanek, P.Eng. of Geo Engineering (MST) Limited R. D. Webster, P.Eng. of Commonwealth Seager Group
Amoco Canada Petroleum Company Ltd. (Amoco) L. Pillman	R.B.A. Arnold, P.Eng. R. H. Czemeres, P.Eng.
Chevron Canada Resources Limited (Chevron) R. A. Pashelka	G. R. Jackson, P.Eng. J. E. Spring, P.Eng.
Dome Petroleum Limited (Dome) R. Drysdale	
Esso Resources Canada Ltd. (Esso) W. Samoil	
Gulf Canada Resources Inc. J. T. Caffrey	
Home Oil Company Limited (Home) C. A. Keck	
Texaco Canada Resources Ltd. M. J. Christie	
Alberta Environment T. R. Bossenberry	
Energy Resources Conservation Board staff H. R. Hansford A. Cassley, P.Eng.	



FEDERATED PIPE LINES LTD. Application 841279

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

OCELOT INDUSTRIES LTD. APPROVAL TO MODIFY ITS EXISTING PECO CENTRAL GAS PLANT TO RECOVER ETHANE-PLUS LIQUIDS

Decision D 85-4
Application 840711

1 INTRODUCTION

1.1 The Application

Ocelot Industries Ltd. (Ocelot) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct facilities at its existing Peco Central gas processing plant (located in Lsd 12-1-49-16 W5M) to remove a mixture of ethane and heavier hydrocarbons (ethane-plus) as a liquid from the sales gas stream leaving the existing gas processing plant. At maximum approved throughputs, the existing plant recovers 261 cubic metres per day (m^3/d) of propane-plus liquid and 923 thousand (10^3) m^3/d of sales gas from 986 x 10^3 m^3/d of raw gas. The proposed addition to the plant would recover 543 m^3/d of ethane-plus liquid from the sales gas stream, thereby reducing its volume from 923 x 10^3 m^3/d to 757 x 10^3 m^3/d.

1.2 The Interventions

Ocelot's application was opposed by a number of companies that participate in the Alberta petrochemical industry by extracting ethane, upgrading it to ethylene, or manufacturing ethylene derivatives. In general, this group's opposition to the application was based on its belief that extraction of ethane at field plants would negatively affect the security of its supply and cost of ethane available to the Alberta petrochemical industry. They suggested that this would seriously erode investor confidence and could mean that there would be no further expansion of the Alberta petrochemical industry.

Ocelot's application was supported by Home Oil Company Limited because it believed that the ethane-plus liquid that would be recovered by Ocelot's proposed facilities would be required as injectant for miscible flood, enhanced oil recovery schemes. Canadian Hunter Exploration Ltd. also supported the application because it believed that a producer has the right and should be entitled to recover separately and market any constituents that make up its gas.

1.3 The Hearing

The application was considered at a public hearing in Calgary, Alberta, on 22, 23, and 24 October 1984, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and F. J. Mink, P.Eng., sitting. Those who appeared at the hearing are shown in Table 1.

Written interventions were also received from Celanese Canada Inc., CIL Inc., Union Carbide Ethylene Oxide/Glycol Company, and Amoco Canada Petroleum Company Ltd. (Amoco), but these parties did not participate at the hearing.

2 ISSUES

The Board believes that it is appropriate to assess this application in a manner similar to that used in ERCB Decision 82-G (Decision 82-G) respecting three field ethane-plus extraction (deep-cut) facilities. Fundamental to this analysis is the Board's responsibility for the economic, orderly, and efficient development of the natural resources of the Province of Alberta and, in general, to have regard for the impact of energy projects on the public interest of Alberta.

For this application, as with others for approval of field deep-cut facilities that have been considered previously, the evidence clearly indicates that approval would result in positive impact on some sectors of the Alberta economy while negatively impacting on other sectors. In order to determine the magnitude of the positive and negative impacts, the Board analysed the application in terms of the following specific issues:

- the degree to which the proposed facilities would recover ethane and other natural gas liquids incremental to those volumes that would be recovered without the facilities;
- the present and future markets for the ethane and other natural gas liquids;
- the cost of the products to be recovered at the proposed facilities compared to the cost of recovering similar volumes of the same products elsewhere in the province;
- the potential impact of the proposed facilities on the existing straddle plant system, and on the Alberta petrochemical industry;

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Ocelot Industries Ltd. (Ocelot) D. G. Hart, Q.C.	W. E. Andrew, P.Eng. B. E. Schellenberg, P.Eng. M. D. Heule, P.Eng. G. Engbloom (of Confer Consulting Ltd.) D. Henderson, P.Eng. (of Duckworth, Price, Henderson & Associates)
Alberta Gas Ethylene Company Ltd. (AGEC) F. R. Foran	R. E. Bowser, P.Eng. Dr. J. E. Feick, P.Eng. D. Ferris, P.Eng.
Dome Petroleum Limited (Dome) F. M. Saville, Q.C.	J. B. Cochrane, P.Eng. E. L. Forgues, P.Eng. H.W.G. Petranik, P.Eng.
Petro-Canada Inc. (Petro-Canada) W. J. Hope-Ross	
Dow Chemical Canada Inc. (Dow) R. A. Neufeld	B. R. Wastle
D. M. Wolcott & Associates Ltd. and Morgan Hydrocarbons Inc. (Wolcott and Morgan) G. N. McDermid	
Home Oil Company Limited (Home) C. A. Keck	
Canadian Hunter Exploration Ltd. (Canadian Hunter) J. S. Mackie	
Atcor Resources Limited (Atcor) D. M. Murray, P.Eng. D. E. Belsheim, P.Eng.	
Energy Resources Conservation Board staff H. R. Hansford B. C. Hubbard, P.Eng. K. Johnston W. J. Schnitzler, P.Eng.	

- the impact of the proposed facilities on the potential for enhanced recovery of oil;
- the economic benefits to Alberta, including the public treasury, resulting from the incremental recovery of ethane and other natural gas liquids;
- the proprietary rights of gas producers;
- the degree of upgrading of resources within Alberta; and
- the conservation and enviromental aspects of the proposed facilities.

The Board sees the first six issues listed above as being of primary importance to its decision, while the last three issues listed are of secondary importance in its consideration of this application.

3 CONSIDERATION OF THE APPLICATION

3.1 Incremental Production of Ethane and Other Natural Gas Liquids

Ocelot's application stated that 63 m^3/d of ethane would be incremental to the province as a result of deep-cutting the sales gas stream at Peco. At the hearing, Ocelot explained that the 63 m^3/d of ethane could be attributed simply to the difference in ethane recovery factors between its proposed facility at Peco, expected to recover about 91 per cent of the ethane in the gas stream, and the average recovery factor assumed for the Empress straddle plants, about 70 per cent.

Ocelot contended that the 63 m^3/d of ethane would only be one component of the total incremental ethane production which would be between 180 and 220 m^3/d. A portion of these latter figures is caused by an adjustment to the 63 m^3/d because Ocelot revised its estimate of the recovery factor at Empress from 70 per cent down to 62.5 per cent. Ocelot claimed that 180 m^3/d of incremental ethane would occur when 577 x 10^3 m^3/d of sales gas leaving the Peco deep-cutter flowed to Empress for reprocessing. The 220 m^3/d of incremental ethane would occur if 577 x 10^3 m^3/d of sales gas left the Peco deep-cutter, but only 425 x 10^3 m^3/d flowed to Empress with the remainder being sold as discount gas within Alberta. Ocelot argued that it could not pursue the discount market at this time without the approval of the proposed deep-cut facility. Ocelot's calculation assumed that the minor effect its deep-cutter would have on the ethane content of the gas flowing to Empress would not alter the ethane recovery at Empress, and presented evidence suggesting this would be the case.

With respect to the heavier natural gas liquids (propane and butanes), Ocelot stated that the proposed facility would result in marginal incremental production because the recovery efficiency at the proposed facility would be only slightly higher than at Empress, and both would be close to 100 per cent.

Ocelot's calculations of incremental liquids were all based on gas sales of 577 x 10^3 m^3/d from the proposed plant. Under the existing contract, up to 425 x 10^3 m^3/d would be sold to TransCanada PipeLines Limited (TransCanada), and the remainder would be sold into the discount gas market within Alberta. Although gas sales from the existing Ocelot Peco plant have historically been about 425 x 10^3 m^3/d (part of which has been discount sales due to reduced takes under the TransCanada contract), Ocelot claimed that the proposed deep-cutter would provide the incentive to accelerate production of the Peco Field and Ocelot was confident that additional discount markets could be found to absorb the increased sales gas production.

AGEC calculated that the incremental production of ethane that would result from the proposed deep-cutter would be 81 m^3/d. AGEC's calculation assumed that all of the 577 x 10^3 m^3/d of sales gas from Peco would flow to Empress. AGEC also calculated that the proposed deep-cutter would reduce the ethane content of the gas flowing past Empress from 3.66 to 3.62 mole per cent which would in turn cause the ethane recovery efficiency at Empress to drop from 64.41 to 64.14 per cent. AGEC argued that sales of gas to the discount market should not affect the calculation of incremental ethane. It contended that about 70 per cent of the incremental ethane production resulting from the Peco deep-cutter would occur only as a result of the increased production rates proposed by Ocelot. AGEC concluded that the volume of incremental ethane would be so small that the proposed facility would be largely a duplication of existing facilities.

Dome also concluded that the volume of incremental ethane resulting from the proposed plant would be very small.

Dow stated that the benefit of the small amount of ethane production from the proposed facility which would be incremental would not offset the negative impact of increased costs and loss of investor confidence in the Alberta petrochemical industry.

The Board has reviewed the evidence regarding incremental production of ethane and has concluded that it would be in the order of 100 m^3/d. The Board's calculation assumes that Peco sales gas volumes would remain constant at 425 x 10^3 m^3/d. The Board, for the purposes of calculating incremental ethane that would result from the proposed deep-cut facilities, is not prepared to accept as incremental those volumes that would result from additional sales to discount markets.

The Board also assumed that the ethane recovery efficiency at the Empress straddle plants would not decrease as a result of the reduction in ethane content of the gas that would occur if the Peco deep-cutter was installed. The Board notes that the AGEC evidence in this regard is based on the premise that the base (pre-Peco deep-cut) ethane content of gas entering the Empress straddle plants is 3.66 per cent. The Board also notes that the figure presented by AGEC, which illustrates the change in ethane recovery factor with changing inlet ethane content, shows a critical dependence on knowledge of inlet ethane content. For example, if the base ethane content were assumed to be something greater than 3.75 per cent, the recovery factor would be affected quite differently by the applied-for facilities to the extent that it could increase with a decrease in ethane content in the inlet. The Board decided to assume a constant recovery factor for its analysis because it does not know with

precision what the ethane content would be when the proposed Peco facilities would go on stream if approved, and also because the change in content due to the proposed facilities would be small. The Board recognizes that this could become a significant factor in the event further deep-cutting facilities are proposed in the future and would require further study at that time.

The Board concludes that although the incremental production of ethane resulting from the proposed deep-cutter would be quite small, its significance may depend on the prevailing ethane supply/demand situation. The incremental recovery of propane and heavier hydrocarbons would be so small that it would be insignificant.

3.2 Present and Future Markets for Ethane-Plus Liquid Recovered at Peco

Ocelot stated that it intended to sell the ethane-plus mix recovered at Peco to miscible flood operators. Ocelot said that miscible flood operators had indicated to it that a shortage of ethane for use as miscible flood solvent would exist at least until the early 1990s and that the proposed Peco facility would be well situated to serve that market. Ocelot stated that it had been negotiating the sale of its liquids with Home, Esso, and Amoco but no commitments to dispose of the ethane-plus mix had been made at the time of the hearing.

AGEC submitted its 10-year forecast of ethane supply and demand in Alberta. It showed that the supply of ethane from existing and approved sources would exceed the provincial demand for ethane, including forecast petrochemical and export demand and including what AGEC considered to be a reasonable allowance for miscible flood use. AGEC's forecast showed that ethane from sources that currently supply the petrochemical industry would be insufficient to satisfy the demand if or when a third ethylene plant was to come on stream, notwithstanding that the total provincial supply would exceed the total provincial demand. Although some small volumes of surplus ethane from the straddle plant system had recently been committed to the miscible flood market, AGEC stated that there would not be a sufficient supply of ethane available from its sources to meet the peak requirement for miscible flood solvent. AGEC's forecast showed that ethane requirements for miscible flooding would reach a peak in the late 1980s and decline thereafter. AGEC suggested that if facilities were put in place to supply the peak requirement, a surplus would exist following the peak and that a levelled demand curve would better suit the existing supply curve.

Dome stated that at the present time, demand for ethane does not exceed supply and would not even by the mid 1990s. At the present time, AGEC takes about 55 per cent of the ethane produced by the straddle plant system, about 45 per cent is exported and a small amount, about 1.5 per cent, is sold for miscible flood use. Dome said that it has long-term commitments to supply ethane to AGEC and for its export volumes and that miscible flood requirements would be satisfied if ethane was available after the petrochemical and export demands had been met.

The Board has reviewed the supply/demand forecast submitted by AGEC. It notes that the forecast shows a relatively close tracking of demand with supply with a moderate excess of supply throughout most of the 10-year forecast period. The Board has also forecast what it considers will be the probable supply and demand of ethane including the probable demand for ethane as a constituent of miscible flood solvent.

The Board's supply forecast is similar to AGEC's forecast, however, it extends beyond 1995. After that year, the Board's forecast shows ethane supply starting to decline slowly due to declining gas deliverability within the province. Additionally, the Board expects that the ethane demand for miscible flood will be somewhat larger than predicted by AGEC. The result is that the Board's forecast suggests that total demand for ethane would be equal to or modestly exceed the supply from existing and approved facilities over most of the forecast period. The Board therefore concludes that for at least most of the next 10 years, the incremental ethane which would result if the Ocelot application is approved could be absorbed in the total market for Alberta ethane.

3.3 Cost of Ethane Recovered at Peco Compared to Other Sources

Ocelot stated that the cost of extracting the ethane-plus mix at its proposed Peco plant would be $12.74/m^3$ in 1986 (excluding shrinkage costs). This cost was based on Ocelot's estimate of proven reserves currently connected to its existing plant. Further, Ocelot explained that if additional proven reserves not yet connected and probable reserves were considered, the calculated processing cost would be reduced to $11.12/m^3$. In response to questioning, Ocelot calculated a processing cost of $17/m^3$ of ethane-plus mix based on a lesser plant throughput (425×10^3 m^3/d sales gas instead of 577×10^3 m^3/d as proposed).

Ocelot estimated the cost of transporting its ethane-plus mix to the miscible flood schemes it would serve to be approximately $16/m^3$. Ocelot said that its estimated total cost of some $27/m^3$ (excluding shrinkage) would be competitive with the cost of ethane or ethane-plus liquids delivered to miscible flood schemes from other existing and approved sources of supply. For the purpose of comparison, Ocelot estimated that processing costs for specification ethane at existing straddle plants would be in the $21 to $22/m^3$ range.

Dome stated that it calculated a cost of $17.23/m^3$ for processing and delivering specification ethane to Fort Saskatchewan from its Dome II plant at Empress. It also estimated that if the Dome I plant was expanded, an additional 7000 barrels per day (1113 m^3/d) of ethane could be recovered for $17.29/m^3$, or an additional 12 000 barrels per day (1908 m^3/d) of ethane could be recovered for $29.56/m^3$. From its comparison of the costs, Dome concluded that the cost of ethane-plus liquid from the proposed Peco plant would be in the same range as the cost of other supplies delivered to the miscible flood market, but would be towards the high end of the range. Dome attributed this mainly to the transportation cost for the Peco liquids which would be higher than that for most other approved or proposed projects.

AGEC's evidence regarding cost of specification ethane delivered to Fort Saskatchewan indicated an average price of $24/m^3$, excluding shrinkage, over the period 1986 to 1990.

The Board has calculated a cost for extracting ethane-plus liquid at the proposed Ocelot plant of $12.09/m^3$ in 1986. The Board used a raw gas inlet rate that would result in 425 x 10^3 m^3/d of sales gas rather than 577 x 10^3 m^3/d as proposed by Ocelot and scaled down Ocelot's estimates of capital and operating costs to reflect the lower production rates.

The Board has compared the cost of $28.09/m^3$ (processing and transportation) for Peco ethane-plus delivered to the miscible flood market with the costs calculated for ethane-plus mix from existing and previously approved straddle and field plants. It has concluded that the costs are within the general range of other plants and that Ocelot would likely be able to sell its liquids competitively to the miscible flood market.

3.4 Impact on Existing Straddle Plant System and Petrochemical Industry

Ocelot submitted an economic analysis of the impact of its proposed deep-cutter on the Empress straddle plants and on the Alberta ethane-based petrochemical industry. It showed that the "upstreaming" effect of deep-cutting the Peco sales gas would cause the cost of recovering ethane at the Empress straddle plants to increase from $69.21/m^3$ to $69.41/m^3$ (including shrinkage). This 20¢/m^3 increase in the unit cost of ethane would be passed along to AGEC, but since only two-thirds of AGEC's total supply of ethane comes from Empress, the 20¢/m^3 would equal 13.3¢/m^3 when applied to the total AGEC supply. Ocelot concluded that the increased ethane cost would cause the price of ethylene in Alberta to increase by 0.02¢ per pound (/lb) of ethylene produced, or about one-tenth of 1 per cent if current ethylene costs 20¢/lb. Over the first year of deep-cut operation, 1986, this would result in an increase in feedstock cost to ethylene derivative manufacturers of $662 000.

Ocelot also calculated a cost impact to the Empress straddle plant operators of $1.3 million in 1986 due to lost revenue from the sale of propane-plus liquids that would have been recovered at Empress but would be recovered at Peco with the proposed deep-cutter.

AGEC reiterated its view that "upstreaming" causes the cost of ethane from the straddle plant system to increase, it undermines the security of ethane supply to AGEC, and it undermines investor confidence in the Alberta petrochemical industry. AGEC calculated that Ocelot's proposal would thus cause the fixed unit cost of ethane extraction at Empress to increase by approximately 25¢/m^3. This, in turn, would result in a cost impact to the ethane-based petrochemical industry of $2 million per year.

Dow stated that any increase in feedstock costs such as would occur from upstreaming could be of serious consequence to the Alberta petrochemical industry, especially when the increased cost results from an action that also erodes the security of supply. Dow said that petrochemical investors are attracted to Alberta because of the cost-of-service structure of the existing straddle plant system, but that approval of upstreaming projects that threaten security of supply and increase ethane cost could jeopardize future investment.

The Board has calculated what it believes to be the impacts on the existing straddle plant system and petrochemical industry using as a base a sales gas volume of 425 x 10^3 m^3/d from the Peco plant. The Board calculated that Ocelot's proposed deep-cutter would cause the unit cost of extracting ethane at Empress to rise by 18¢/m^3 to $20.58/m^3$ in 1986. This would increase production costs that would be passed on to AGEC by approximately $810 000 in 1986 and would represent a total present value cost of $5.8 million for the period 1985 to 2000. In addition, the Board believes that AGEC would incur a loss of revenue from reduced sales of ethane to the export or miscible flood markets because a reduced amount of ethane would be available for recovery at Empress. The Board estimates this cost would be $890 000 in 1986 and represent a total value of $6.2 million by the year 2000, discounted at a rate of 15 per cent.

With respect to the Empress straddle plant operators, the Board calculated that the increase in unit production costs of propane-plus recovered at Empress and the lost revenue due to decreased sales of propane-plus would add up to approximately $1.6 million in 1986 or a total

of $13.4 million by the year 2000, discounted at a rate of 15 per cent. The Board notes that a portion of the above-mentioned costs would be borne by the federal and provincial governments as well as AGEC and the straddle plant operators, as will be described in more detail in Section 3.6.

3.5 Impact on the Potential for Enhanced Oil Recovery (EOR)

Ocelot stated that its proposed project would have a positive effect on the potential for EOR because it would provide an incremental supply of miscible flood solvent over a forecast period when demand would exceed supply. Additionally, Ocelot contended that EOR operators could acquire ethane at a lower cost from Peco than from certain other sources.

AGEC stated that there would not be a sufficient volume of ethane available from its supply sources to satisfy the forecast demand for EOR projects after meeting the petrochemical and export requirements. In response to questioning regarding the possibility of giving priority to sales to the EOR market over export sales, AGEC stated that it had a long-term contractual commitment to export ethane that is surplus to the needs of the Alberta petrochemical industry and that those export sales are necessary to maintain the viability of the Cochin Pipeline system.

Dome suggested that the EOR requirement for ethane should be met by supplies from other proposed or previously approved field plants where none or only part of the sales gas would be reprocessed at a straddle plant. This would lessen the impact on the existing straddle plant system and petrochemical industry. Dome also suggested that the cost of ethane from the proposed Peco facility to the EOR market would be higher than for ethane from other approved and proposed supplies because the Peco supply would not be near any existing transportation infrastructure.

Dow expressed its view that if ethane was not available from the proposed plant to supply the EOR demand, it would simply be made available from other sources. Further, Dow pointed out that Ocelot's own evidence indicated that the cost of ethane from Peco to the EOR market would be comparable to other supplies so no savings would result for those operators purchasing Ocelot's liquids.

The Board is of the view that to the extent incremental ethane-plus liquids would be made available within the province to the EOR market over a period of possible supply shortage, the proposed facility represents a positive impact on the potential for EOR. In this instance, the impact would not be great because the volume of incremental liquids from the proposed facility would be small. The benefit of incremental ethane to EOR operators would be the displacement of some corresponding volume of more valuable propane as injectant. The Board has not calculated the actual monetary value of the benefit of the incremental volume of ethane but believes it would depend on the difference between the selling price of the ethane and the value of an equivalent volume (in the reservoir) of propane.

3.6 Economic Benefits and Costs

The Board has calculated the quantifiable economic benefits and costs that would result from the proposed deep-cut facilities using an approach very similar to that used in ERCB Report 82-G. The distribution of benefits and costs which results from the Board's analysis, assuming all parties are fully taxable, are summarized in Table 2. The analysis was done over the 1985 to 2000 period.

As shown, the development of deep-cut facilities would be of significant financial benefit to Ocelot and the potential EOR operators who are expected to purchase the ethane-plus mix from the project. The analysis also shows a benefit resulting from the deep-cutter, albeit, more modest than that to be experienced by Ocelot, for the gas industry in general, and the two levels of government. The latter benefits are largely attributed to increased gas production and royalties, and taxes resulting from incremental recovery of liquids if the deep-cutter is installed. The Board's analysis confirms that the burden of development results in reduced cash flow to the petrochemical industry and the straddle plants at Empress. The reduced cash flow to these parties nearly offsets the increases identified for all others. In aggregate, however, the project does generate a modest positive net present value of some $400 000.

The Board notes that a number of companies affected by the development are not in a taxable position at this time or are unlikely to be taxable during the 1980s. To that extent, they are likely to be in a position to defer their taxes during a portion of the operating life resulting in a lower effective tax rate than shown in the Board's summary. The net effect would not alter the overall net benefit of the project although it is likely to result in a reduced benefit of the project to government, an increased loss to the straddle plants, and a greater benefit to Ocelot than is shown in the summary.

3.7 Proprietary Rights of Gas Producers

Ocelot stated that in principle, it should have the right to extract liquids from gas streams it has discovered and developed, particularly since it showed that such extraction is in the public interest.

TABLE 2 BOARD SUMMARY OF INCREMENTAL IMPACT AFTER TAX*

	0%	15%
Ocelot/EOR	35 545	13 480
Petrochemical Industry	(16 965)	(7 085)
Straddle Plants	(19 605)	(7 910)
Gas Producers	(415)	425
Provincial Government	(1 535)	1 105
Federal Government	(1 650)	380
	(4 625)	395

* Assuming full marginal tax rates.

AGEC said that the Board's mandate to ensure the orderly and efficient production of hydrocarbons should not allow the extraction of liquids in the field if that would adversely affect the existing straddle plant system. This would not necessarily preclude all field extraction of liquids but would limit it to cases where such extraction would have no adverse impact on the straddle plant system.

Dome stated that the proprietary rights of gas producers is only one part of the public interest and that the Board should not approve applications for projects that would adversely affect the previously approved straddle plant system and the petrochemical industry.

The Board maintains the same view that it has expressed in previous decisions on applications of a similar nature, that gas producers having the right to extract components of their gas as separate streams is generally in the public interest. The Board emphasizes again, however, that this is only one part of the overall public interest and clearly must be considered along with all other positive and negative aspects affecting it.

3.8 Upgrading of Resources

Ocelot stated that it agreed with the Board's view in Decision 82-G that to the extent that incremental liquids would be recovered at field plants, the province's resources would be upgraded. Ocelot suggested, therefore, that its proposed project represented significant upgrading of resources.

The Board is of the view that the Ocelot proposal would result in a modest upgrading of resources to the extent that incremental liquids would be recovered. The incremental recovery would, however, be small and thus this is not an important issue in this instance.

3.9 Conservation and Environmental Aspects

Ocelot stated that its proposed deep-cut facility would use efficient proven technology and that all requirements of environmental and conservation regulations would be fully satisfied.

The Board is satisfied that the proposed facilities would be efficient. With respect to environmental considerations, the Board notes that the proposed facility and the existing Peco plant process sweet gas only and also notes that Alberta Environment indicated that it was satisfied with Ocelot's application prior to the hearing.

4 DISCUSSION AND CONCLUSIONS

The Board's analysis of the Ocelot application indicates that approval of it would result in a modest incremental recovery of ethane in the province, some 100 m^3/d. The Board expects the provincial supply-demand situation for ethane and the cost of recovering it at the Peco plant to be such that the incremental ethane could be absorbed by the market-place, particularly for EOR purposes. The incremental ethane used for EOR would likely free up equivalent-in-reservoir volumes of propane and heavier hydrocarbons which are expected to have a ready market. The recovery of incremental volumes of ethane would likely mean a modest increase in upgrading of Alberta resources within the province. Additionally, the proposed plant expansion would meet conservation and environmental standards and be acceptable from those viewpoints.

All of the above aspects of the application are positive in terms of the public interest and suggest that the Ocelot application should be approved. This is particularly the case given that a producer does have a proprietary right to remove liquids from its produced gas stream, subject to it being in the overall public interest. However, in this case, the incremental volume of ethane to be recovered is small compared to total provincial production, some 100 m^3/d added to an expected total of over 25 x 10^3 m^3/d. Thus, the previously mentioned positive effects on the public interest are not overwhelming.

The economic study clearly shows that the additional liquid removal at the Peco plant and the opportunity to produce greater volumes of gas to replace the shrinkage would result in economic benefits to Ocelot. These would be small when compared to the industry as a whole, but in terms of a producer such as Ocelot, would be substan-

tial. There would also be related economic benefits to the Alberta Treasury through increased royalties, and perhaps to both the Alberta and Federal Treasuries through increased taxes.

Approval of the Ocelot application would result in negative economic impacts on the straddle plant owners and the petrochemical industry in Alberta. The impacts on the latter would not be great compared to the total industry in the province but it would be an additional negative impact for an industry which is already experiencing difficulties due primarily to a number of factors extraneous to Alberta. Witnesses for more than one petrochemical company appeared at the hearing indicating that continued approval of field deep-cut facilities to upstream the straddle plant system would further erode the confidence of petrochemical manufacturers in Alberta and reduce the chances of additional plants locating within the province. The Board understands the concerns of the petrochemical industry and believes it to be a legitimate issue in measuring the public interest. Although the Board cautioned all proponents developing straddle plants that their approval would not preclude subsequent approval of upstream field facilities and that such possibilities must be a business risk to be borne by the straddle plant owners, it continues to hold the view that a proliferation of field plants upstreaming the straddle plants to the detriment of the petrochemical industry would not be in the public interest.

In this particular situation, having itemized the quantifiable beneficial impacts likely to result from approval of the Ocelot application, the Board must weigh those against the negative impacts from an approval on the straddle plant owners and the petrochemical industry. Direct costs can be estimated, as they have been in this report, and compared to the benefits. However, in terms of the petrochemical industry and its ongoing viability in the province, the cumulative effect of all upstreaming applications is of importance. Additionally, the economic health of the industry at any particular time and thus its ability to absorb additional costs is relevant in considering an upstreaming application. The economic health of the petrochemical industry is of course greatly affected by many factors including the global petrochemical and energy situations and the policies of many governments.

The economic impacts of approving the application are summarized in Table 2 of this report. They show that if the application is approved, the present worth, discounted at 15 per cent, of the negative impacts on the straddle plants and petrochemical industry would be almost as large as the benefits gained by Ocelot, the EOR operators, gas producers, and the various levels of government. As a result, the total economic impact on the province is positive but not very large.

The Board recognizes that its economic calculations are not precise and also that they incorporate a number of arbitrary assumptions and decisions. For example, the Board declined to recognize as incremental ethane recovery those volumes which might result from incremental discount gas sales as Ocelot suggested it should. Nevertheless, the Board believes that its economic calculations give a reasonable approximate answer and also that they must be made on some established and consistent basis, however arbitrary that might be.

The fact that there are not large overall economic benefits associated with the Ocelot proposal requires the Board to focus greater attention on the degree to which the petrochemical industry might be affected.

The Board's analysis of the application shows that a present-value cost of $7 million to the petrochemical industry would result from approval of the Peco facility. The Board believes that it is useful to balance that cost along with other costs against the benefits of the project to arrive at an overall cost or benefit to the province. The Board does not believe, however, that the overall cost or benefit that can be calculated fully describes the potential effect of the project on the public interest, particularly as it relates to the petrochemical industry. Indeed, the Board heard considerable evidence from interveners at the hearing regarding the generally poor condition of the Alberta petrochemical industry at this time and the effect that any further negative influences could have on future investment here. For this reason, the Board believes that the current status of the industry and the cumulative effects of all upstreaming applications must be kept in mind.

The cumulative effects are considerable, but approval of the Ocelot application would add little to them. Also, the Alberta Government recently cleared the way for the petrochemical industry to purchase shrinkage gas at in-province discount prices. This has a potential beneficial effect on the industry considerably greater than the negative impact of all upstreaming approvals to date. That element, coupled with the fact that the incremental negative impact from the Ocelot project would be small, leads the Board to conclude that it should approve the application. Once again, the Board cautions that it will not necessarily approve all upstreaming projects because, at some point, the cumulative negative impacts on the petrochemical industry may be so great that denial will be necessary because of concerns for the overall Alberta public interest.

The Board has given a great deal of thought to the manner of dealing with applications to install deep-cut

facilities and remove ethane and other natural gas liquids at field plants upstream of existing straddle plants. Consideration of the Ocelot application and the experience of having dealt with several earlier ones has lead the Board to set out a number of principles which it believes should be generally adhered to in dealing with such applications. Clearly, each case must be decided on its own merits, however, the Board believes setting out the following standards will assist it and the industry respecting possible future applications.

(a) If an application for deep-cut facilities is not opposed by any party that potentially could be directly and adversely affected, and if it meets conservation and environmental standards, it would likely be approved.

(b) If an application for deep-cut facilities requires a hearing, and if it does not meet the requirements set out in items (c) and (d) below, the Board would not normally schedule the hearing until such deficiencies are rectified.

(c) Applications must contain information relevant to the Alberta public interest and demonstrate that approval of the deep-cut facilities would be in the public interest. Considerations to be included could be those identified by the Board in past reports or others that the proponent may wish to add.

(d) Applications must include evidence indicating that the party proposing a deep-cut facility which would upstream the straddle plant system has investigated the possibility of alternative and more suitable arrangements with the owners of the straddle plant system. The Board expects that when such discussions occur, each party would recognize the public benefits from the rights of producers to extract products from the gas stream and the possible benefits and efficiencies gained by utilizing existing facilities to produce those products.

(e) Interveners that oppose applications for deep-cut facilities on grounds that the straddle plant system and petrochemical industry will be negatively impacted must present evidence respecting those negative impacts. The evidence should be as extensive as possible and should be aimed at demonstrating to the Board that the subject application should not be approved because it is contrary to the overall public interest.

(f) The questions of whether a deep-cut facility will result in the recovery of incremental volumes of natural gas liquids for the province as a whole, and whether there is likely to be markets for such incremental volumes, will be important in deciding applications. If an application would have a significant negative impact on the straddle plant system and petrochemical industry, and if there are no related incremental volumes of liquids, or if the liquids in question are already in a surplus situation or would not be competitive in the market-place, the chances of the application being approved would be reduced.

(g) Applications for deep-cut facilities upstream of straddle plants invariably result in a redistribution of dollars insofar as economic impacts are concerned. If a particular application would have a significant negative impact on the straddle plant and petrochemical industry, would redistribute dollars, but in fact would reduce the overall economic benefits to the province, the chances of the application being approved would be reduced.

5 DECISION

The Board hereby approves Application 840711 by Ocelot Industries Ltd. to install additional facilities at its existing Peco gas plant to recover additional volumes of ethane-plus natural gas liquids. The approval will be issued upon receipt of approval from the Minister of the Environment respecting environmental matters.

DATED at Calgary, Alberta, on 28 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

THOMSON-JENSEN PETROLEUMS LTD.
RATEABLE TAKE OF GAS FROM THE ATMORE NISKU A, MCMURRAY B, AND WABISKAW C POOLS

Decision D 85-5
Application 840530

The Board adopts the examiners' recommendation as set out in the attached report.

DATED at Calgary, Alberta, on 22 January 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

THOMSON-JENSEN PETROLEUMS LTD. RATEABLE TAKE OF GAS FROM THE ATMORE NISKU A, MCMURRAY B, AND WABISKAW C POOLS

Examiners' Report E 85-1
Application 840530

1 INTRODUCTION

1.1 The Application

Thomson-Jensen Petroleums Ltd. (Thomson-Jensen) applied under section 23 of the Oil and Gas Conservation Act (the Act) for an order to equitably distribute gas production among the wells in the Atmore Nisku A, McMurray B, and Wabiskaw C pools (the A, B, and C pools, respectively).

1.2 The Hearing

The application was considered at a public hearing on 13 and 14 November 1984, in Calgary, Alberta, by Board-appointed examiners, J. R. Pow, P.Eng., H. R. Keushnig, P.Eng., and R. N. Houlihan, P.Eng. The participants at the hearing are listed in Table 1.

BP Resources Canada Limited (BP), Lyleton Corporation (Lyleton), and Suncor Inc. (Suncor) submitted interventions.

1.3 Background

Currently, the Board designates the A and B pools as multi-well pools and the C Pool as a single-well pool, as shown by Figures 1 and 2. In January 1976, the Board approved commingling in the wellbore for gas production from the A and B pools (Board Order MU 358), and gas production from the pools began in March 1976. Production from the C Pool commenced in March 1982.

As shown by Figures 1 and 2, Thomson-Jensen operates 10 of the 14 wells currently producing gas from the A, B, and C pools, while BP and Lyleton operate 3 wells and 1 well, respectively.

The total production from the A, B, and C pools to September 1984 is 687 million cubic metres (10^6 m^3). About 56 per cent was produced from the Thomson-Jensen wells, while 34 and 10 per cent were produced from the BP and Lyleton wells, respectively.

The gas produced from the wells in the A, B, and C pools is sold to Suncor under three separate gas sales contracts with Thomson-Jensen, BP, and Lyleton. All three contracts are based on reserves and include other reserves in addition to those of the A, B, and C pools. The seller of gas has the option of fulfilling gas nominations from any reserve dedicated to the contract.

1.4 Procedural Matters

At the opening of the hearing, Lyleton moved to have the application dismissed, for the reason that section 23 of the Act (Appendix I) does not operate to give Thomson-Jensen the relief for which it has applied. It further submitted that there is no other provision of the Act which gives the Board the authority to grant this application. Lyleton argued that, given the opening words of section 23, the Board must be satisfied that there are valid reasons to restrict the total production from the pool before it may limit the total amount of gas that may be produced under subsection 23(a) and apportion that restricted production of gas equitably among the well owners in the pool under subsection 23(b). Lyleton argued that when a pool can be produced at its full capacity and there are no market restrictions preventing any owner from producing its reserves to the best of its well's capability, there is no conservation reason to restrict the total production from the pool. Lyleton submitted that, in effect, Thomson-Jensen is seeking compulsory unitization over which the Board currently has no jurisdiction. In summary, Lyleton took the position that before the Board may issue an order under section 23, there must be a valid reason to restrict the total production from the pools and that Thomson-Jensen has given no such valid reason; that, if there is no reason to restrict total production, there is no reason to apportion production among the wells in the pools; and that, therefore, section 23 does not operate to give the applicant the relief it seeks and the application should be dismissed. BP supported Lyleton's submission.

Thomson-Jensen replied that the Board has jurisdiction over the application under section 23 because the application seeks both an equitable distribution of gas in the pools to the various owners and, by implication, a limitation, if necessary, on the other parties' production.

The examiners ruled that they would address the Lyleton submission in their report.

The examiners note that the Board has the jurisdiction to consider all bona fide applications which are prop-

erly made to the Board under the apparently appropriate section of the Act, and that, indeed, the Board has an obligation to do so. The examiners note Lyleton's argument that there must be a valid reason to "restrict the amount of gas . . . that may be produced . . . from a pool", within the meaning of the opening words of section 23, before the Board may exercise its jurisdiction under subsections 23(a) and (b). The examiners are of the view that the existence of a valid reason is a question of fact that is subject to investigation at a hearing, and that the Board has jurisdiction to hear this application.

2 ISSUES

The examiners consider the issues to be

- the need for a rateable-take order,
- if there is a need, the method of distributing production, and
- the delineation of the A, B, and C pools.

3 NEED FOR A RATEABLE-TAKE ORDER

3.1 Views of Thomson-Jensen

Thomson-Jensen stated that it has not been given the opportunity to receive an equitable share of gas produced from the A, B, and C pools, and it requested that future production be distributed in proportion to each producer's share of reserves. Thomson-Jensen estimated the reserves for the subject pools using a material balance method, and proportioned the reserves using a ratio of individual wellbore net pay to the sum of net pays of all eligible wells in the subject pools. The applicant indicated that it considered an eligible well to be a well tied into a gathering system and capable of economic production. Using wellbore net pay criteria, Thomson-Jensen calculated that it would be equitable to take 77 per cent of the pools' future production from its own wells, 22 per cent from the BP wells, and 1 per cent from the Lyleton well (see Table 2). The cumulative production proportions to 31 December 1983 from the subject pools are 56, 34, and 10 per cent for Thomson-Jensen, BP, and Lyleton, respectively, and Thomson-Jensen contended that if production from the wells continues in these proportions, its reserves will continue to be drained.

In support of its claim, Thomson-Jensen submitted a projection of existing production performance for the wells grouped by common ownership, and estimated, as shown in Table 2, that 46, 24, and 30 per cent of future production from the pools would be produced by the Thomson-Jensen, BP, and Lyleton wells, respectively. Comparing its reserve-based estimate of 77 per cent with its future production forecast of 46 per cent, Thomson-Jensen suggested that the difference between the numbers represents the reserves that it will lose to drainage in the future.

Thomson-Jensen stated that pressure data are not a reliable basis for determining drainage because most wells in the pools are currently producing.

Thomson-Jensen indicated that its wells are producing at capacity, and that the market is not a limiting factor. It pointed out that its gas sales contract with Suncor is reserve-based, with the contract area being larger than the subject pools. The applicant noted that contract nominations, which are based on total contract reserves, can be fulfilled from any reserve dedicated to the contract, a practice known as cross-dedication. Thomson-Jensen submitted that since cross-dedication is allowed in the contract, nominations based on total contract area have permitted BP and Lyleton to produce more than their share of gas from the subject pools. It said that it has a right to the share of gas that underlies its lands and that it can eventually produce all of its gas from the subject pools.

Thomson-Jensen explained that it has been unable to negotiate a satisfactory solution to remedy the problem of drainage. It requested that a rateable-take order be issued to equitably distribute gas production among the wells in the A, B, and C pools.

3.2 Views of BP

BP indicated that the three operators in the subject pools are producing under essentially the same types of gas sales contracts. It explained that it cannot be concluded that Thomson-Jensen has not had the opportunity of producing or receiving its share of the gas from the A, B, and C pools. BP claimed that Thomson-Jensen is constrained by the capability of its wells and not sales contract restrictions.

BP questioned whether some of the wells to which Thomson-Jensen attributed pay are capable of producing significant additional quantities of gas. The well located in Lsd 10-24-67-18 W4M was named as an example.

BP disagreed with Thomson-Jensen's method of forecasting future production by grouping wells according to common ownership rather than on an individual well basis. BP suggested that by grouping the wells in this manner, the wide variety of individual well declines and the presence of marginal wells are masked, thus distorting an estimate of future production. Using an individual

well decline method, BP estimated that the Thomson-Jensen wells will obtain some 62 per cent of the pools' future production, this being 16 percentage points greater than Thomson-Jensen's estimate of 46 per cent (see Table 2).

BP stated that Thomson-Jensen's claim of drainage cannot be substantiated without pressure evidence.

In response to Thomson-Jensen's comments regarding the cross-dedication of reserves, BP emphasized that Thomson-Jensen itself is also cross-dedicating reserves. It submitted that the percentage of gas produced from the subject pools in relation to total contract volumes is slightly higher for Thomson-Jensen than for BP.

BP concluded that Thomson-Jensen appears to be seeking the advantages of both an area-based contract allowing cross-dedication and a pool contract recognizing the owners' reserves in the pools. BP stated that there are no valid grounds for the application and that there is no need either to restrict or to allocate the production from the pools. BP submitted that the application should be denied.

3.3 Views of Lyleton

In its intervention, Lyleton presented an argument similar to BP's. Lyleton expressed the opinion that Thomson-Jensen's current rate of pool production is determined by the productivity of its wells. It submitted that there are no conservation reasons to restrict production from the subject pools. It also submitted that production need not be restricted for reasons of equity because, under the rule of capture, an operator owns only those hydrocarbons its wells can produce. Hence, where an operator produces its wells at full capacity, there can be no drainage in the legal sense and, accordingly, no reason to restrict production under section 23 of the Act.

With respect to a forecast of future gas production, Lyleton stated that the applicant's estimate of its future production is too low. It noted that Thomson-Jensen ignored pool production after 31 December 1983 which was increased by the installation of booster compression. Using an individual well decline method, Lyleton estimated future production from the Thomson-Jensen wells to be 73 per cent of the pools' total, this being 27 percentage points greater than Thomson-Jensen's future production estimate of 46 per cent, and only 4 percentage points less than Thomson-Jensen's estimated 77 per cent share of the pools' reserves.

Lyleton noted the differences in pool interpretations submitted by Thomson-Jensen and BP and suggested that no one can be sufficiently certain of the pools' reserves to justify asking the Board to proportion gas production on that basis.

For these reasons, Lyleton maintained that the application should be denied.

3.4 Views of Suncor

In its intervention, Suncor confirmed that it has gas purchase contracts with each of Thomson-Jensen, BP, and Lyleton. It indicated that the contracts are identical in form and operation, being reserve-based contracts in which the seller is free to cross-dedicate reserves available from its contract lands to meet daily nominations.

Suncor stated that each seller has an equal opportunity to produce its share of gas from the subject pools. It submitted that no seller is limited by the lack of market opportunity, pointing out that each seller's gas deliveries have been consistently less than contract nominations.

Suncor therefore submitted that the application should be denied.

3.5 Views of the Examiners

The examiners note that in Decision 77-23[1] the Board stated that before approving an application under section 23, it must be convinced that a well owner has been or is being deprived of the opportunity to obtain his just and equitable share of the production from any pool. The examiners decided that this is the main consideration to be addressed in determining whether a need exists for a rateable-take order in the subject pools.

The examiners understand that Suncor has area-based gas purchase contracts with each of Thomson-Jensen, BP, and Lyleton, and that these contracts are identical in form and operation. The examiners also understand that Suncor has nominated maximum daily quantities to each seller, and that no seller is limited by the lack of market opportunity. The examiners note that none of the sellers has met Suncor's maximum daily nomination. Under these circumstances, the examiners conclude that the only limitation on Thomson-Jensen's ability to produce from the subject pools is well capability.

Where there are no market restrictions on production, where there are no conservation reasons to restrict production from a pool, and where the only limitation on production is well capability, the examiners conclude

[1] Application by Ridgewood Resources Ltd. for the rateable take of gas from the Big Bend McMurray B Pool and for the declaration of a common processor and a common carrier.

that a producer is not being deprived of the opportunity to obtain its just and equitable share of the production from the subject pools.

The examiners note that Thomson-Jensen does have, and has recently exercised, opportunities to increase well deliverability in order to increase its recovery of gas from the subject pools. These include drilling replacement wells, adding booster compression to existing wells, and conducting workovers on existing wells.

Accordingly, the examiners conclude that the Board should decline to issue an order respecting a distribution of production for the pools and that the application should be denied.

4 METHOD OF DISTRIBUTING PRODUCTION

Because the examiners are recommending denial of the application, they believe that there is no need to address the method of distributing production among the wells in the pools.

5 POOL DELINEATION

The examiners have considered the detailed evidence submitted by Thomson-Jensen and BP regarding the delineation of the A, B, and C pools. However, as the examiners are recommending the denial of the application for reasons unrelated to this evidence, they believe that this matter warrants mention only for the purpose of assisting the Board in its administrative responsibility of delineating the pools of the Province.

The examiners find no justification for changing the boundaries currently in effect for the A Pool, as shown by Figure 1. On the other hand, on recognizing that the C Pool produces from the McMurray Formation in continuity with the B Pool, they propose that the C Pool be incorporated into the B Pool and that the B Pool be amended to cover the shaded area shown on Figure 2.

6 RECOMMENDATION

For the reasons given in section 3.5, the examiners recommend that the application be denied.

DATED at Calgary, Alberta, on 17 January 1985.

J. R. Pow, P.Eng.

H. R. Keushnig, P.Eng.

R. Houlihan

R. N. Houlihan, P.Eng.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Thomson-Jensen Petroleums Ltd. (Thomson-Jensen) J. I. Parker C.L.K. Higgins	G. D. Metcalfe, P.Eng. of T. Fekete & Associates Consultants Limited R. C. Mann, P.Geol. of Hugh Mann & Associates
BP Resources Canada Limited (BP) K. F. Miller	D. C. Elliott, P.Geol. J. 't Hart, P.Geol. D. B. MacInnes, P.Eng. R. A. Nicoud, P.Eng.
Lyleton Corporation (Lyleton) D. A. Holgate	R. D. Pryor, P.Eng. I. Martin, P.Eng. and R. C. Hankel, P.Geol. of Martin Petroleum Consulting Ltd.
Suncor Inc. (Suncor) K. S. MacFarlane	A. J. Wells, P.Eng.
Energy Resources Conservation Board staff K. I. Fisher, C.E.T. C. C. Heinrich C. D. Hill A. A. Gervais	

TABLE 2 PRODUCTION SHARES OF THE COMBINED ATMORE NISKU A, MCMURRAY B, AND WABISKAW C POOLS (Expressed as Rounded Percentages)

Source of Estimates	Owners' Shares of Future Production Under Current Conditions			Owners' Shares of Future Production Based on Reserve Estimates		
	T-J (%)	BP (%)	Lyleton (%)	T-J (%)	BP (%)	Lyleton (%)
Thomson-Jensen	46	24	30	77	22	1
BP	62 (58)[a]	19 (25)[a]	19 (17)[a]	62[b]	37[b]	1[b]
Lyleton	73	17	10	–	–	–

Cumulative Production to September 1984:

T-J (%)	BP (%)	Lyleton (%)
56	34	10

a Production shares if BP installs booster compression and reduces abandonment pressure.

b Submitted by BP as planimetered rock volume reserve proportions, with no suggestion that future production be distributed accordingly.

APPENDIX I EXCERPT FROM THE OIL AND GAS CONSERVATION ACT

23. The Board, after a public hearing, may, by order, restrict the amount of gas and oil produced in association with gas that may be produced during a period defined in the order from a pool within Alberta

(a) by limiting, if the limitation appears necessary, the total amount of gas that may be produced from the pool, having regard to the efficient use of gas for the production of oil and to the demand for gas from the pool, and

(b) by distributing the amount of gas that may be produced from the pool in an equitable manner among the wells in the pool for the purpose of giving each well owner the opportunity of producing or receiving his share of the gas in the pool.

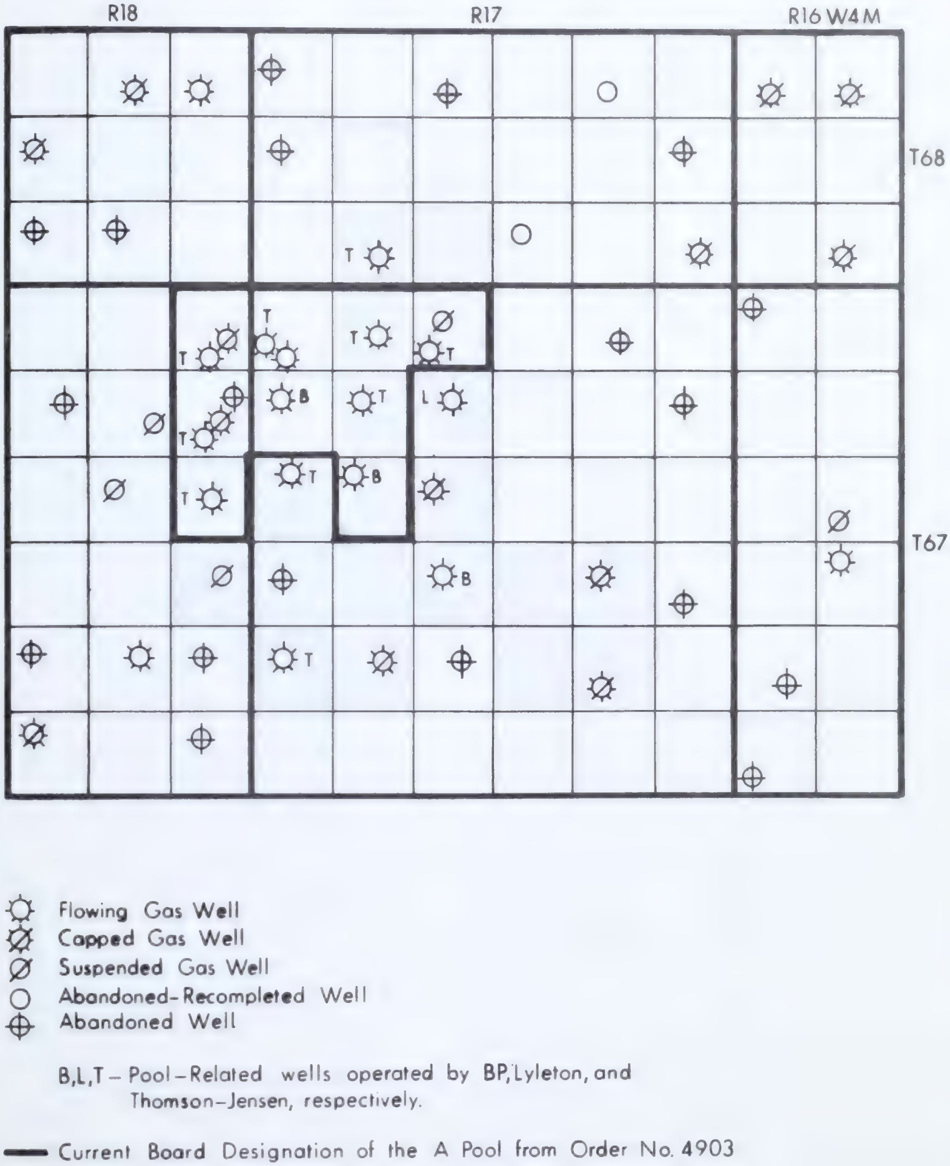


FIGURE 1 - ATMORE NISKU A POOL

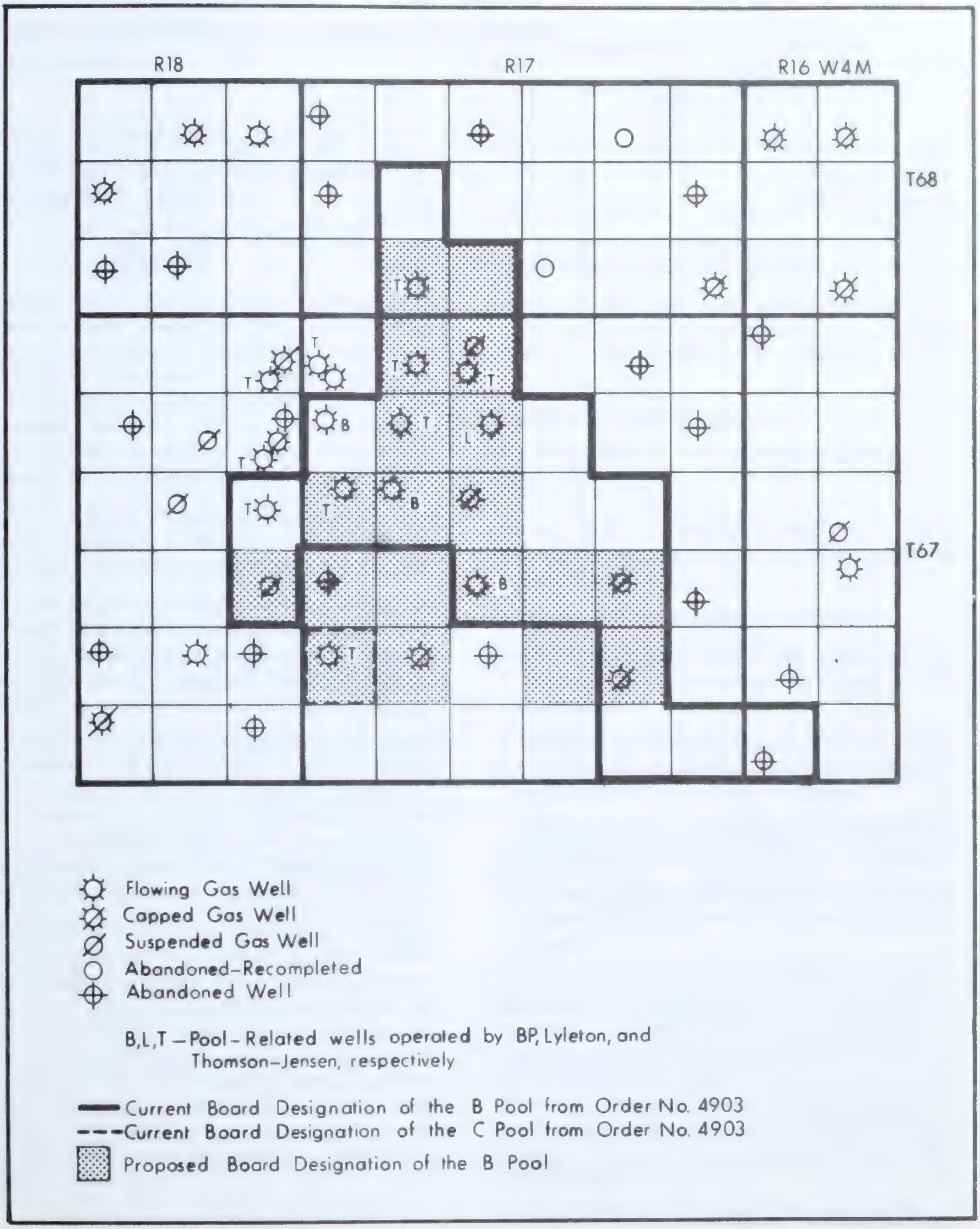


FIGURE 2 - ATMORE Mc MURRAY B AND WABISKAW C POOLS

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

DOME PETROLEUM LIMITED EXPERIMENTAL IN SITU SCHEME LINDBERGH SECTOR

Decision D 85-6
Application 840739

1 THE APPLICATION, HEARING, AND DECISION

Dome Petroleum Limited (Dome), on behalf of its partners Sulpetro Limited and CNG Producing Company, applied pursuant to section 10, subsection (1) of the Oil Sands Conservation Act, for approval to develop a 16-well cyclic steam experimental project in the Cummings Zone of the Cold Lake Wabiskaw-McMurray Oil Sands Deposit in the northwest quarter of section 10, township 56, range 6, west of the 4th meridian.

The project would involve 1 existing well and 15 new wells to be slant-hole drilled from a well pad located in the centre of the quarter section (see attached figure).

Dome also proposed to construct a battery in legal subdivision 9 of section 10, township 56, range 6, west of the 4th meridian, which would include the production and steam injection equipment associated with the project.

A public hearing of the subject application was held on 11 December 1984 in Elk Point before Board members, G. J. DeSorcy, P.Eng., L. A. Bellows, P.Eng., and N. A. Strom, P.Eng. The subject application was heard in conjunction with Applications 840736 and 840986 by PanCanadian Petroleum Limited. Those who appeared at the hearing are shown on the attached table.

Based upon the evidence and undertakings of the applicant, the positions of the interveners, and its responsibilities under the Oil Sands Conservation Act, the Board decided to grant the application and advised the participants of its decision at the conclusion of the hearing. The approval of the project would, however, be subject to the undertakings by Dome, conditions which the Board would specify, and ministerial approvals. The following report gives the reasons for the Board's decision and the conditions of the ERCB approval.

2 THE INTERVENTIONS

Mr. Yaremkevich, whose home is located on 2.6 hectares of land in the southeast quarter of section 10, township 56, range 6, west of the 4th meridian, opposed granting of approval of the subject application because of the following concerns:

- a decrease in his property value due to its close proximity to the Dome project site,
- a significant increase in the volume of truck traffic on the road fronting his property as well as the dust and danger to his children associated with such a traffic increase,
- odours and noise from the project,
- the possibility of an oil spill or sour gas leak, and
- the loss of privacy.

The Elk Point Surface Rights Association (EPSRA) supported the granting of approval of the application but expressed concerns regarding:

- land use and the placement of drilling pads,
- noise levels produced by the Dome project as well as the cumulative effects of noise from all such projects in the area,
- emissions and odours produced by the Dome project as well as the cumulative effects of emissions and odours from all such projects in the area,
- public accessibility to environmental monitoring results and related data from the oil industry in the area, and
- the impacts of increasing oil industry-related traffic volumes and the application of oily sand on area county roads.

In discussing these concerns, the EPSRA suggested that the ERCB noise guidelines set forth in Interim Directive ID 80-2 are inadequate for the current level of heavy oil development in the Lindbergh area. It further suggested that a revised guideline be considered in which noise levels produced by oil field operations not be permitted to exceed the ambient background noise level, expressed as Leq, of the subject area by more than 5 decibels (dBa).

A group of Elk Point/Lindbergh area residents, the Town of Elk Point, and the Counties of Vermilion River and St. Paul all filed interventions in support of the application. Generally, they anticipated positive social and economic impacts from the Dome project and believed that environmental effects would be satisfactorily managed.

3 THE REASONS FOR DECISION

The Board accepts that a well spacing of less than 16 hectares is necesary for this type of scheme and that the scheme should provide Dome with some valuable information. The Board notes that the locations of both the well pad and the battery are such that existing well leases would be expanded to incorporate the new facilities, thus minimizing the additional surface disturbance of the infill wells and the battery. Further, the Board is satisfied that the use of a well pad would improve Dome's opportunities to manage any surface environmental problems.

Dome submitted a completion program for its proposed slant wells that incorporated surface casing and a production string designed for thermal service and thermal cement to be used the full length of each well. This completion, combined with the knowledge that Dome does not intend to exceed the fracture pressure of the Cummings zone, satisfies the Board that near-surface aquifers would be protected. The Board does intend to condition its approval with an injection pressure limitation.

The Board is satisfied with all other technical aspects of the project. Since such matters were not at issue during the hearing, the Board is not addressing them in this report.

Dome stated it plans to gather and flare all casing vent gases and other produced gases once battery construction is completed. In the interim, incineration equipment would be available should odours be detected. Dome's environmental surveillance plans include monitoring of all gases going to flare, the use of sulphation stations to monitor downwind ambient air quality, and periodic continuous air monitoring for a 2- to 3-month period on an annual basis.

The Board is satisfied that the emission control measures to be implemented by Dome will ensure that there will be no safety hazards in connection with the emissions and that fugitive odours will be minimized. As well, the Board notes that if odours do occur, complaints should be directed to Dome and the ERCB so that they may be investigated and rectified in a timely manner. It also notes that Dome is prepared to make the results of its environmental monitoring available to nearby residents and the public.

The Board is satisfied that the volume of truck traffic that will be generated by the Dome project is not unreasonable. In stating this, the Board recognizes that the trucking of production from the proposed project site to Dome's facilities in section 18, township 55, range 5, west of the 4th meridian, is a temporary situation as Dome plans to bring a pipeline into the project site for transportation of crude bitumen production. Also, Dome has further committed to reduce truck traffic impact by controlling the scheduling of traffic into and out of the project site, by maintaining safety standards with respect to the state of vehicles used by Dome's truck contractors, and by advising vehicle operators on the need for care when travelling into and out of the project site.

The Board recognizes the potential problem of noise impact as a result of the proposed project and associated operations. However, it is satisfied that with diligent efforts by Dome to minimize such impacts, noise levels will be within acceptable limits. These efforts include the electrification of pumpjack motors, conducting a noise impact study which would include baseline ambient monitoring prior to the commencement of operations as well as monitoring of ongoing operations, and instituting noise reduction programs should the ERCB noise guidelines be exceeded. Respecting the noise guideline suggested by Mr. Bugej of 5 dBa above preproject ambient levels, the Board has reservations as to its practicality. However, the Board agrees that the ERCB noise guidelines, as well as the need for noise regulations, should be reviewed and this is being done by the ERCB in consultation with Alberta Environment.

Finally, the Board believes that, in view of Dome's commitments mentioned previously, the appropriate environmental controls will be in place to minimize the impacts of the proposed project on surrounding residents and the value of their properties.

4 OTHER MATTERS

The concept of a community advisory committee was discussed by several interveners at the hearing. The Board endorses this concept but believes it should be extended to include all concerned parties from both the rural and urban "community". The Board further believes that, through such a committee, an annual meeting could be organized at which area oil industry representatives could report to committee members and residents the results of environmental monitoring programs and future plans concerning projects such as that of Dome. Should the community advisory committee concept not proceed, the Board believes that there are sufficient benefits to be gained from an annual meeting between the oil industry operators and the community and that local oil industry operators should consider initiating such a forum.

The problem of heavy oil-related traffic impacts on county roads was discussed at some length during the hearing. Generally, the discussion centred around the increased volumes of traffic, the resulting accelerated deterioration of the road surface, the need for increased road maintenance, and safety hazards posed by large tank

trucks travelling at high rates of speed. There was also considerable discussion of the use of waste oil and oily sand from oil cleaning plants as a dust suppressant on road surfaces.

The Board recognizes the adverse impacts of local heavy oil development on county roads but does not have jurisdiction in this matter. The Board is aware that the Advisory Committee on Heavy Oil and Oil Sands Development is reviewing such matters with the intent of co-ordinating prompt actions by municipal authorities and others to mitigate adverse effects. The Board intends to refer the concerns tabled at this hearing to this committee as well as to the counties concerned and Alberta Transportation.

5 DECISION

The Board approved Application 840739 at the conclusion of the hearing. In granting this application, the Board notes the following conditions:

- The results of the air monitoring program conducted in conjunction with the experimental scheme in the northeast quarter of section 10-56-6 W4M, including data from the sulphation stations and continuous air monitoring devices, shall be made available to nearby residents and the local public on a semi-annual basis.
- The results of the noise impact study conducted in conjunction with the experimental scheme in the northeast quarter of section 10-56-6 W4M shall be submitted to the ERCB and made available to nearby residents and the local public within 2 months from the commencement of operations.
- Should noise, determined by the noise impact study noted above, exceed the maximum permissible noise levels set out in ERCB Interim Directive ID 80-2 or any new directives or regulations which may result from the review under way, noise attenuation devices shall be installed, or other means of noise reduction undertaken, to reduce noise to acceptable levels.

Subject to the receipt of the required approvals from the Minister of Energy and Natural Resources and the Minister of the Environment, the ERCB will issue its approval.

DATED at Calgary, Alberta, on 4 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

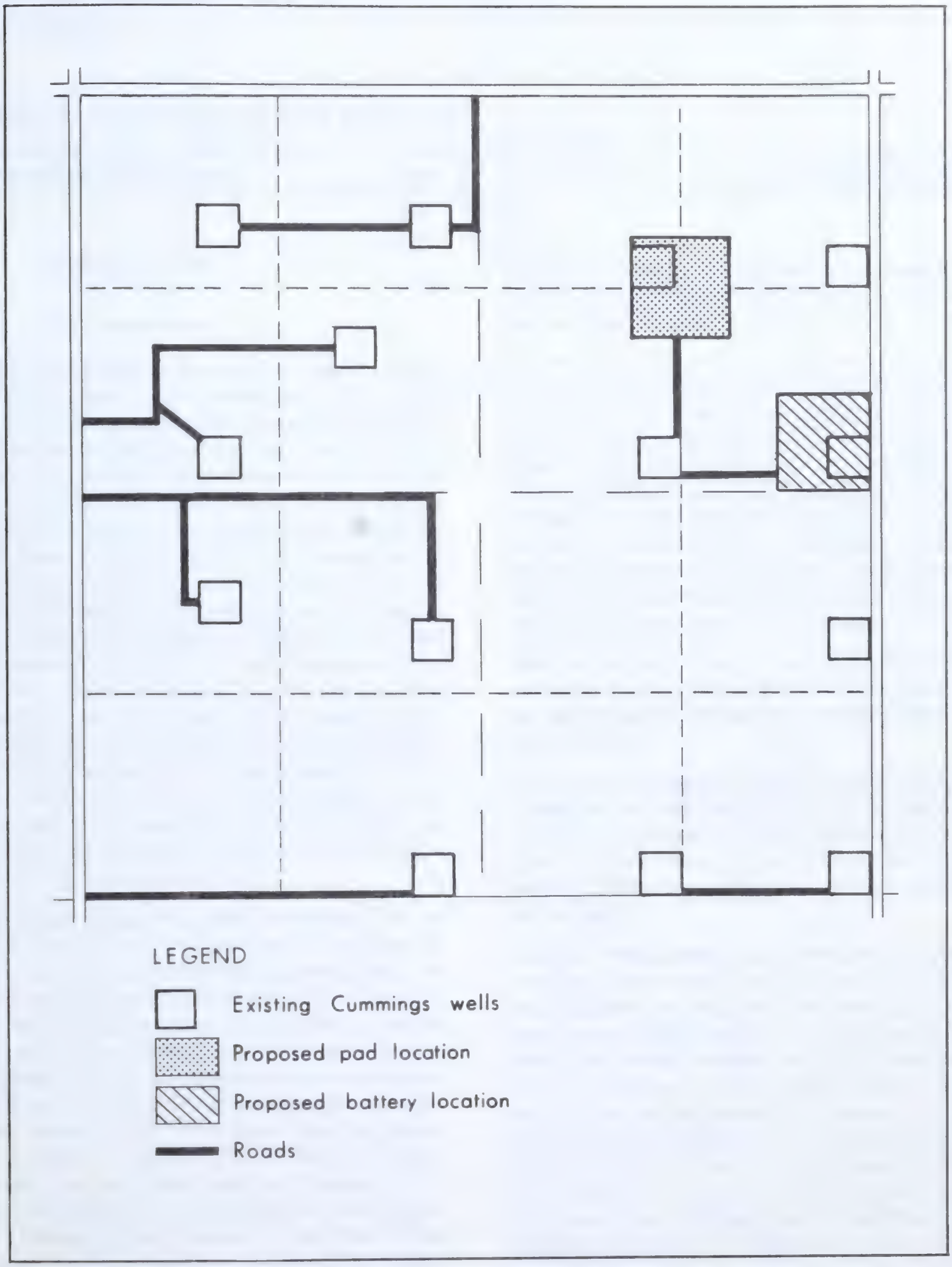
G. J. DeSorcy, P.Eng.
Vice Chairman

N. A. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Dome Petroleum Limited (Dome) A. L. McLarty	R. M. Scarborough, P.Eng. S. Hoffman, P.Eng. B. R. Croft, P.Eng. W. Wohwchuk, C.E.T.
D. Yaremkevich	D. Yaremkevich
D. Kadutski	
Elk Point Surface Rights Association (EPSRA) A. Bugej	A. Bugej R. Danyluk D. Torok
Group of Elk Point-Lindbergh Area Residents J. Darling	J. Darling
Town of Elk Point L. P. Vincent	L. P. Vincent
County of Vermilion River F. A. Wheat	F. A. Wheat
County of St. Paul R. Smith	R. Smith
Energy Resources Conservation Board staff M. J. Bruni J. R. Nichol, P.Eng. B. P. Fenlon, P.Eng. M. R. Sills	



EXISTING AND PROPOSED SURFACE FACILITIES. Section 10-56-6W4M

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

PANCANADIAN PETROLEUM LIMITED REDUCED WELL SPACING AND CLEANING PLANT LINDBERGH SECTOR

Decision D 85-7
Applications 840736 and 840986

1 INTRODUCTION

1.1 The Applications

PanCanadian Petroleum Limited (PanCanadian) applied pursuant to section 4.030, subsection (1)(a) of the Oil and Gas Conservation Regulations to reduce the existing 16.2-hectare (ha) well spacing to 4.0-ha well spacing in section 3, township 56, range 6, west of the 4th meridian (section 3). It is anticipated that with 4.0-ha spacing, primary recovery from the Cummings zone of the Cold Lake Wabiskaw-McMurray Oil Sands Deposit could be increased to about 6.5 per cent of original bitumen in place (OBIP) compared to the expectation of 2.5 per cent OBIP under the 16.2-ha spacing. PanCanadian proposed to directionally drill up to 12 wells from a pad in the southwest quarter of section 3, with the pad being centrally located in the quarter section (see Figure l). A surface development plan for the other three-quarters of section 3 was not provided as operating experience from directional wells in the southwest quarter is needed in order to determine the most suitable drilling and completion mode (slant, deviated, or vertical wells) for optimum production operations.

PanCanadian also applied pursuant to sections 7.001 and 7.002 of the Oil and Gas Conservation Regulations for approval to construct and operate a cleaning plant to be located in legal subdivision 6 of section 3 (see Figure 1). The proposed cleaning plant would handle hydrocarbon production trucked from various PanCanadian wells in the general vicinity and is designed to process 1000 cubic metres per day (m^3/d) of total fluid production. Clean crude bitumen would be pipelined from the plant to Lloydminster via Husky's Cold Lake-Lloydminster pipeline. Produced water would be disposed of to a proposed disposal well to be drilled at the cleaning plant site. Although vapour recovery at the plant is not proposed for initial operation, a provision for vapour recovery is incorporated into the plant design.

1.2 The Interventions

Interventions expressing concern and qualified opposition to PanCanadian's applications were submitted by Mr. and Mrs. C. Kozicky who live and farm on the southwest quarter of section 10, township 56, range 6, west of the 4th meridian (section 10), directly north of section 3.

Mr. and Mrs. J. Shymkiw, who reside in the southeast quarter of section 3, and Mr. and Mrs. H. Shymkiw, owners of the northeast quarter of section 3, were not opposed to the development of the southwest quarter of section 3 (the cleaning plant and the well pad), provided certain conditions were implemented to reduce impacts and avoid safety risks. However, they submitted that the remainder of the 4.0-ha spacing application should not be considered until a specific surface development plan is put forward by PanCanadian for consideration by the surface owners of those lands.

Interventions in favour of both applications were submitted by the Town of Elk Point, the County of St. Paul (County), the County of Vermilion River, and Ms. J. Darling.

Ms. Darling represents a group consisting of approximately 84 members who reside within the boundaries of either the Elk Point or Lindbergh sectors of the Cold Lake Oil Sands Area. A list of signatures of those wishing to be represented by Ms. Darling was filed at the hearing.

The Elk Point Surface Rights Association (EPSRA) submitted an intervention reminding participants of certain safeguards and objectives that should be borne in mind, but the EPSRA neither opposed nor endorsed the applications by PanCanadian. The EPSRA submitted a list of its members residing within a 2-mile radius of section 3 but was not prepared to disclose a complete list of its members and their land ownership descriptions. The EPSRA did not wish to supply a complete list for three reasons: some of the members work for oil companies, some members felt it could harm their negotiations with the oil companies, and the EPSRA constitution states that members' names will be held in confidence.

1.3 The Hearing

A public hearing was held on 11 and 12 December 1984 in Elk Point before Board members, G. J. DeSorcy,

P.Eng., N. A. Strom, P.Eng., and L. A. Bellows, P.Eng. The subject applications were heard in conjunction with Application 840739 by Dome Petroleum Limited (Dome). Some of the interveners' evidence submitted during the Dome hearing applied to all applications and was considered as such by the Board. Those who appeared at the hearing are shown on Table 1.

The hearings were originally scheduled to commence 4 December 1984, however, due to a request for adjournment by Mr. and Mrs. J. Shymkiw and Mr. and Mrs. H. Shymkiw, the hearings were delayed.

As a matter of convenience, the proposed development for the southwest quarter of section 3, including the spacing, the wells, and the cleaning plant, will be discussed separately from the reduced spacing in the remaining three-quarters of the section.

2 SOUTHWEST QUARTER DEVELOPMENT

2.1 Issues

The Board believes the main issues are:

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
PanCanadian Petroleum Limited (PanCanadian) E. S. Decter	D. V. Castellino A. Oxtoby, P.Eng. K. J. McKay A. R. Pool, C.E.T. M. M. Metwally, P.Eng. N. A. Chase K. Young-McLaren
Amoco Canada Petroleum Company Ltd. J. N. Havelock	
Mr. and Mrs. J. Shymkiw and Mr. and Mrs. H. Shymkiw P. T. Johnston	L. Piotrowski
Mr. and Mrs. C. Kozicky	Mr. and Mrs. C. Kozicky
Elk Point Surface Rights Association (EPSRA) A. Bugej	A. Bugej R. Danyluk D. Torok
Group of Elk Point-Lindbergh Area Residents J. Darling	J. Darling
Town of Elk Point L. P. Vincent	L. P. Vincent E. Buck
County of St. Paul (County) R. Smith	R. Smith R. Bouchard
Energy Resources Conservation Board staff M. J. Bruni J. R. Nichol, P.Eng. B. P. Fenlon, P.Eng. M. R. Sills	

- the need for the reduced spacing and the cleaning facilities
- truck traffic
- noise
- odours and emissions
- impact on ground water
- land/soil management
- fencing

2.2 The Need for the Reduced Spacing and the Cleaning Facilities

PanCanadian stated that the need for the closer well spacing is to increase primary recovery from 2.5 to approximately 6.5 per cent of the OBIP. To this end, PanCanadian plans to drill up to 12 directional wells from a centrally located pad. Drilling 12 wells from a pad, as opposed to 12 vertical wells, would save a considerable amount of agricultural land by reducing the acreage needed for roads and well sites. PanCanadian considered a part of the need to be for the evaluation of pumping techniques in directionally drilled wells. This evaluation will assist in determining the most suitable type of wells (vertical or directional) to be used for the remaining three-quarters of section 3.

Currently, each well produces to its own lease tank with the hydrocarbon and produced water being trucked separately. PanCanadian stated that with the significant increase in the well density, a proliferation of truck traffic could be expected if current trucking practices were to continue. This would increase PanCanadian's expenditures and encroach on the quality of life in the area. PanCanadian stated that by drilling from a pad and locating the cleaning plant near the centre of section 3, it would be able to reduce the overall trucking and keep the disturbance to the quality of life to a minimum. The cleaning plant site would provide a single facility where a pipeline moving bitumen to sales could be installed and would also be used as a utility distribution centre supplying fuel gas, water, and electric power to the individual well sites, which would substantially reduce the overall truck traffic and noise levels.

None of the interveners questioned the need for the plant or the wells in this quarter section. Ms. Darling, the Town of Elk Point, and the County all supported the development for its economic benefit to the general Lindbergh area. Tax revenues, lease revenues, and business and job opportunities were cited as tangible evidence of the positive impact to the community. These parties expressed confidence in the Energy Resources Conservation Board (ERCB) and Alberta Environment for control of any environmental impacts.

The Board is satisfied that the reduced spacing will improve recovery and thereby improve conservation. The Board also believes that wells directionally drilled from a central pad provides an opportunity to minimize the disturbance to the agricultural activity in the quarter section.

The Board is satisfied the cleaning plant is needed to process the hydrocarbon product to pipeline specifications to take advantage of the transportation and marketing opportunity provided by the Husky pipeline. The cleaning plant and pipeline would eliminate the current need for trucking of unprocessed production to a Lloydminster cleaning plant.

2.3 Truck Traffic

PanCanadian submitted that, with the cleaning plant and associated utilities in operation, truck traffic into the southwest quarter of section 3 would be restricted to the trucking of production to the cleaning plant, well servicing operations, and employee movements. Access to the section would be from the north-south road on the west side of section 3. Access to the cleaning plant would be from a lease road running east-west at the centre-section line. Within the section, the north-south lease road immediately west of the J. Shymkiw residence would be restricted to light trucks and for hauling bitumen from the 3A-3 well to the cleaning plant (refer to Figure 2). In terms of truck routing in the general Lindbergh area, PanCanadian stated it had met with other operators, Alberta Transportation, and representatives from the ERCB to discuss truck traffic, truck routes, and ways to minimize the impacts on local residents.

PanCanadian plans to haul bitumen 7 days a week to the cleaning plant but stated that it would restrict the trucking to daylight hours. It said that truck drivers would be instructed to use specified access roads, to travel at reduced speeds on county roads, and to avoid excessive use of jake brakes. PanCanadian said it would be prepared to cancel the service contract of any trucker who does not follow these guidelines.

To control dust created by truck traffic, PanCanadian stated that it would supply oily sand to the county for use as a dust suppressant. The main access roads to section 3 would be oiled regularly but dust control is not planned for the roads within section 3.

Mr. Kozicky stated that the projects would only create more traffic on the north-south road past his home, thereby increasing noise and dust problems. He stated that PanCanadian had previously undertaken to oil the road but had not done so to date. Mr. Kozicky also stated that he lived near the top of a gentle incline and when

the trucks used their jake brakes it was enough to "rattle the glasses in my cupboards". Mr. Kozicky agreed that, should the speed of the trucks be reduced, some of his problems would be lessened. He also expressed his wish to have traffic eliminated one day per week, preferably Sunday.

Mr. Kozicky expressed concern over PanCanadian's use of a Dome lease road that runs east-west at the north end of section 3. He submitted that dust from traffic on that road settled on his forage crop at the south end of section 10, thereby lowering its quality. He also expressed concern over a lack of compensation from PanCanadian for the use of the road.

Counsel for the Shymkiws argued that there was uncertainty as to how many trucks would be using the north-south road to the west of the J. Shymkiw residence, and also that PanCanadian had not had any realistic talks with Dome to try to establish what would be the overall traffic impact from the combination of the Dome and PanCanadian operations in the near vicinity of section 3.

During the drilling and construction phase, the Board expects traffic to be at its peak. During this time, the Board would expect PanCanadian to take suitable steps to alleviate traffic congestion and the adverse effects of it on local residents. Some steps that could be taken are: scheduling arrivals and departures of the various construction groups so as to reduce peaking during hours of most frequent use by local residents, designating routes that various groups must travel thereby eliminating the use of only one particular road, setting specific speed limits in and around section 3, and marking trucks such that the individual trucks owned or contracted by PanCanadian would be readily identifiable.

The Board believes that the installation of the well pad, cleaning plant, and products pipeline connection would significantly reduce the amount of truck traffic that would otherwise occur during production operations. Although traffic activity would still be fairly significant, with due care and attention by the applicant, problems can be minimized and the impacts on local residents kept at modest levels.

During all phases of operation, the Board believes that PanCanadian's instructions to its truckers should be explicit, in order that PanCanadian can enforce its conditions. Speed limits should be set for the main access roads and the use of jake brakes near private dwellings should be minimal. The Board realizes that during the construction and drilling phases, limiting all truck traffic to a 6-day week is not practical. However, after drilling is completed and the wells placed on production, the Board believes the use of heavy trucks, except under exceptional circumstances, could be prohibited on Sundays as requested by the Kozickys.

In summary, the Board believes the impact of truck traffic from the proposed PanCanadian scheme can be held to acceptable limits if particular care is taken by PanCanadian and other operators in the area to minimize traffic, co-ordinate planning, and enforce safe and sound driving standards. At the same time, the Board recognizes that truck traffic causes an increase of concern on the part of many residents in the area, not only as it relates to the PanCanadian project but also with respect to other operators. For this reason, the Board would require PanCanadian to submit a report to the ERCB demonstrating the results of its efforts to minimize truck traffic impacts. The report would deal with the matters mentioned earlier in this section, including documenting co-ordination efforts with other operators, outline routes to be followed, summarize trucking hours and driving standards, and any other steps taken to reduce impacts. The Board would also require periodic reports in future, upon request by the ERCB, which show that efforts are continuing to co-ordinate the truck traffic matters in the area.

2.4 Noise

PanCanadian undertook to continue the noise impact assessment program that is now under way in section 3. The program would be expanded to include drilling of the infill wells and the operation of the cleaning plant and associated trucking. PanCanadian stated that its continuing plans for a noise survey did not include servicing operations, however, it acknowledged the need for it to be included.

PanCanadian undertook to try to secure a quiet drilling rig for the drilling program. If this was not possible, PanCanadian would take steps to install silencing devices on any rig acquired. As the drilling operations are scheduled to take approximately 40 days and written results from the noise surveys would likely be available only after drilling was completed, PanCanadian agreed to verbally contact the residents in the immediate vicinity of the drilling site with the results of the noise surveys.

PanCanadian stated that once in operation, it would install electric motors on the pump jacks to mitigate motor noise. It stated servicing would take place in daylight hours only and that initially a service rig could be at the pad almost constantly. PanCanadian hoped to minimize servicing with time and experience. By restricting access routes and trucking to daylight hours, the applicant submitted that noise from trucking would be minimized.

PanCanadian agreed that should the noise from drilling, trucking, or the cleaning plant operations exceed ERCB

guidelines or should PanCanadian receive complaints about the noise, it would immediately undertake corrective measures.

Mr. Kozicky's concerns about noise were related to trucking and are discussed in the previous section of this report.

The EPSRA stated that noise from servicing operations is a major source of noise in the area and that any noise assessment survey must include service rig noise.

Counsel for the Shymkiws pointed out that his clients were very concerned about the noise from trucking operations and in particular the use of the north-south road to the west of their residence.

The Board believes there will be both short-term and long-term noise effects; the short-term occurring during drilling and construction and the long-term occurring during well servicing, cleaning plant, and trucking operations.

The Board notes that PanCanadian has agreed to take significant steps to minimize any noise problems during the drilling phase. The Board is satisfied that with due care and attention PanCanadian will be able to meet existing ERCB noise guidelines.

The Board suspects that noise impacts from servicing operations would be less disruptive if PanCanadian conducted servicing operations only during daylight hours. The noise assessment survey to be completed after production start-up should include measurements when servicing operations are under way.

The Board is generally satisfied with the undertakings by PanCanadian to carefully monitor noise and to promptly implement mitigative measures if complaints occur.

In addition, the Board recognizes that there are concerns, as expressed by the EPSRA, with the existing ERCB guidelines for noise as specified in ERCB Interim Directive ID 80-2. These guidelines, as well as the need for noise abatement regulations, are currently under review by the ERCB in consultation with Alberta Environment.

2.5 Odours and Emissions

PanCanadian stated that initially it did not plan to install a vapour gathering system at the cleaning plant and also would not be gathering gas production from wells on primary production as it expected that gas production at both the cleaning plant and wells would be negligible.

PanCanadian said it would be conducting air monitoring downwind of the cleaning plant and pad site over the initial 4-month period of operation. Should it be demonstrated that there are hydrocarbon or hydrogen sulphide emissions causing odour problems, PanCanadian would install a vapour recovery system.

The EPSRA stated they would like to see all produced gas, other than that used for fuel gas, flared.

The counsel for the J. Shymkiws stated his clients were concerned with the possibility of odours coming from the plant as they lived directly downwind of the plant.

The Board believes that there could be a significant volume of vapours emanating from the cleaning plant depending upon the nature of fluids received and the process conditions. With that in mind, the Board would require PanCanadian to design the facility such that vapour recovery would be readily implemented at any time required during future operations.

The Board agrees that gas emanating from the wells on primary production would likely be modest initially and may not present a problem. However, when PanCanadian initiates steam stimulation operations and flowlines the wells to the plant, vapour gathering would almost certainly be necessary. During this mode of operation, casing vent gases and tank vapours would most likely have to be gathered. This is where the pad concept with centralized facilities offers particular advantages and the Board would not anticipate any problems in being able to gather all casing vent gases and tank vapours as and when total volumes increase. The result should be minimum odour or other problems.

2.6 Impact on Ground Water

The Shymkiws and the EPSRA were concerned with the possible contamination of domestic water supplies due to the drilling operations and the proposed water disposal well.

PanCanadian stated that to ensure potable ground waters would not be contaminated by its proposed water disposal well, it would, in accordance with standard disposal well completion procedures, run three strings of protective piping: 100 metres of surface casing cemented to surface, a production casing string cemented to surface, and a tubing string sealed with a packer at the bottom of the hole. It also stated that annual isolation tests would be performed to ensure that communication had not developed between the tubing and casing. All production wells would also be completed with surface casing.

PanCanadian confirmed its commitment to conduct annual water analyses on three domestic water wells in the immediate vicinity of section 3 as a precautionary measure to ensure that its operations were not affecting domestic water wells.

The Board is generally satisfied that the applicant's plans for casing and completing production wells and the water disposal well will conform with standard ERCB requirements that are designed to ensure complete protection of ground-water aquifers. It notes also that further site-specific application for the disposal well is required and that the details will be fully reviewed at that time.

The Board endorses PanCanadian's commitment to test domestic water wells and notes that results from the tests will be made available to water well owners and the ERCB.

2.7 Land/Soil Management

PanCanadian stated that the topsoil had been stripped from the lease sites in the southwest quarter of section 3 in response to the landowner's request that topsoil be stripped before winter freeze-up. The topsoil was stockpiled and will be feathered out in the form of berms around the drilling pad and cleaning plant sites. PanCanadian expects the topsoil to be spread over an area one-quarter to one-third the size of the entire lease and expects the height of the berms to be a maximum of 2 feet.

PanCanadian noted that the height of the berm would vary from lease to lease depending upon the amount of topsoil existing at each lease. It was also noted that it has the option of fencing the entire lease or to allow farming to the edge of the berm.

PanCanadian indicated that its topsoil stripping and storage practice was based on basic reclamation guides that state that "sound reclamation begins when construction begins".

PanCanadian stated that the cleaning plant site would gently slope to the southwest corner of the site where an evaporation pond would collect plant site surface water.

The counsel for the Shymkiws was concerned that the topsoil stripping that had taken place to date had not been done with sound reclamation plans in mind. The Shymkiws were also concerned with the control of surface waters at the plant site.

The EPSRA were concerned with the construction of the berms and in particular concerned with the height of the berms and the possible safety hazard the berms caused in farming operations.

The Board is satisfied that PanCanadian has applied sound soil management practices and has had effective consultation with the landowner in that regard. As well, the Board notes that the pad drilling proposed for the southwest quarter of section 3 offers advantages in terms of land and soil management by minimizing the overall land disturbance.

The Board understands that PanCanadian is working within existing general guidelines set by Alberta Environment's Land Reclamation Division and by guidelines set by the Canadian Petroleum Association.

2.8 Fencing

PanCanadian proposed to fence the cleaning plant site with a 6-foot frost fence and, in accordance with the landowner's request, to fence the well pad site with a barbed wire fence. PanCanadian stated it had fenced three sides of its ecology pit in Lsd 13-3-56-6 W4M where oily, sandy wastes are collected and that to alleviate Mr. Kozicky's concerns respecting public safety, it would fence the fourth side so as to fully enclose the ecology pit.

Mr. and Mrs. Kozicky and counsel for the Shymkiws expressed some concern that the current and proposed fencing of the pad, cleaning plant, and ecology pit sites may not provide effective security to discourage entry by youngsters.

The Board considers that PanCanadian's plans for fencing, including the fencing of the fourth side of the ecology pit, to be largely adequate but notes that PanCanadian may eventually consider it preferable to fence the well pad with a frost fence if trespassing is a concern.

3 SPACING IN THE EAST HALF AND NORTHWESTQUARTER OF SECTION 3

PanCanadian submitted its application for reduced well spacing for all of section 3 in anticipation of an enhanced recovery project in the section by the mid to late 1980s. It stated that the bottom-hole locations for the infill wells were selected to set up 7-spot patterns for future enhanced recovery operations. PanCanadian did not submit plans for the surface locations of the infill wells as the results from the directional wells in the southwest quarter of section 3 are deemed critical to the decision on well configuration (slant, directional, or vertical) for the remainder of the section. The applicant stated that if the concept of producing wells from a pad was not technically successful in the southwest quarter, and if it was technically, environmentally, and economically viable to drill the wells in a manner acceptable to the landowner, it would proceed in accordance with the landowner's wishes in the rest of the section. PanCanadian acknowledged that current information allowed it to estimate that thermal recovery performance would substantially improve recovery. However, its major uncertainty is whether directional (or equivalent slant

hole) wells would be economically viable to operate, having regard for potential completion and operation difficulties. Therefore, it was unable to commit to further drilling pad plans.

The counsel for the Shymkiws argued that the spacing application for the remaining section area should not be considered at this time because of the number of unknowns respecting surface development plans. He further argued that PanCanadian should have to present any results from experience in the southwest quarter to support its plans for surface development associated with reduced bottom-hole spacing before it moves into the remaining three-quarters of the section.

The Board is satisfied that the increased well density proposed (16 wells per quarter section) will provide much higher recovery of the bitumen resources compared to that attainable under the existing spacing density of four wells per quarter. Also, the Board notes that the 4.0-ha spacing applied for is consistent with the spacing adopted by other operators in the area and generally reflects an expectation of optimum thermal recovery design.

The Board is concerned, however, that the impact on the land surface and impact to the residents in the immediate vicinity cannot be properly addressed at this time because PanCanadian is unable to commit to a surface development plan. Moreover, the Board believes that PanCanadian would have to have regard not only for the views of the landowner upon whose land the wells and facilities are being installed, but also for the concerns of nearby residents. Especially when sustained enhanced recovery operations are going to be instituted, all manner of impacts, including casing vent gases, tank vapours, noise, land use, and traffic routes, would have to be weighed along with the basic engineering and economic factors. In conclusion, the Board would require disclosure of complete development plans and the opportunity for public review prior to approval of such developments.

4 OTHER MATTERS

4.1 Roads

PanCanadian stated that when spreading oily wastes on county roads, it adhered to:

- the 400-barrel-per-mile guideline set by the ERCB,
- guidelines set by the Saskatchewan-Alberta Waste Disposal Co-Op (Co-Op), and
- the requirements of the county that sufficient oil be present in the sand waste before spreading.

It submitted it does not analyse the waste for sand, oil, or salt content before spreading but does analyse the material in the ecology pit on an annual basis. PanCanadian stated that studies done by the Co-Op indicated that if most of the salt water was removed from the oily sand, there would not be a significant salt runoff problem. PanCanadian undertook to supply the EPSRA with the information from the Co-Op.

The EPSRA was concerned with the oil and salt content of the sand being disposed on the roads. They said that road conditions had deteriorated since the oil industry came into the area and by spreading sand, oil, and brine on the roads, maintenance was made more difficult.

The County stated that should the two projects be approved, the resource revenue added to the additional tax revenue would significantly aid the County in its ability to provide better road construction, upgrading, and maintenance in the future.

The County noted that it has experience with the spreading of oil on roads and realizes the problems involved. The County also stated there were general problems with the road maintenance in the heavy oil areas and, in fact, had for the past 3 years allocated an extra road maintenance machine to this area. The County noted that the EPSRA was concerned with the level of maintenance and would take this message to council and hopefully improve the service.

The Board believes there is a need to improve the controls and/or guidelines for the spreading of the waste oils and is prepared to work with the government departments, counties, industry, and public to ensure all views are heard. It will initiate discussions with these parties to get a system of road review in place.

4.2 Communication

PanCanadian stated that it had taken steps to communicate with local residents and to that end held an informational meeting on 4 October 1984 to discuss its activities. PanCanadian noted that the Shymkiws had refused to meet with one particular company representative.

Counsel for the Shymkiws stated that his clients were concerned with the lack of communication taking place between PanCanadian and his clients, and felt PanCanadian should have met with them to discuss its current and future activities within section 3. He observed that PanCanadian had started stripping topsoil and hauling gravel without notifying either the Shymkiws or the Kozickys.

In the Board's view, frequent communication between landowners and industry is essential and the ERCB is

willing to facilitate communications and assist in mediation of differing opinions. The Board believes that a landowner-oil industry advisory committee should be established to aid in promoting more widespread, regular communications between industry and landowners.

5 DECISION

The Board is prepared to approve reduced well spacing and primary production in the southwest quarter of section 3 in accordance with the single well pad plan submitted by PanCanadian. The approval will be subject to the following conditions:

- PanCanadian shall inform the ERCB's Wainwright area office and the Shymkiws of the drilling rig selected and of any steps taken to minimize noise from the rig.
- Results of the noise survey to be conducted during drilling operations shall be communicated verbally to the Shymkiws and the ERCB immediately after completion of the survey. A written report summarizing the results of the survey must be submitted to the Shymkiws and the ERCB at a later date.
  - Noise surveys from service rig operations shall also be provided to the ERCB and the Shymkiws.
  - PanCanadian shall report to the ERCB respecting its ongoing efforts to minimize impacts of truck traffic.

The Board defers its decision respecting reduced well spacing for the northwest quarter and east half of section 3 until such time as PanCanadian submits a surface development plan for the area, including environmental impact considerations.

The Board is prepared to approve Application 840986 for the cleaning plant in Lsd 6-3-56-6 W4M, subject to the following conditions:

- PanCanadian shall report to the ERCB and interveners to its application the outcome of its procedures to reduce trucking related impacts.
- Facilities shall be installed so that all tank vapours can be gathered with minimum delay as and when necessary.
- An air monitoring survey shall include monitoring of the cleaning plant. Results from the survey shall be made available to the nearby residents and the ERCB.

DATED at Calgary, Alberta, on 4 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

N. A. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Board Member

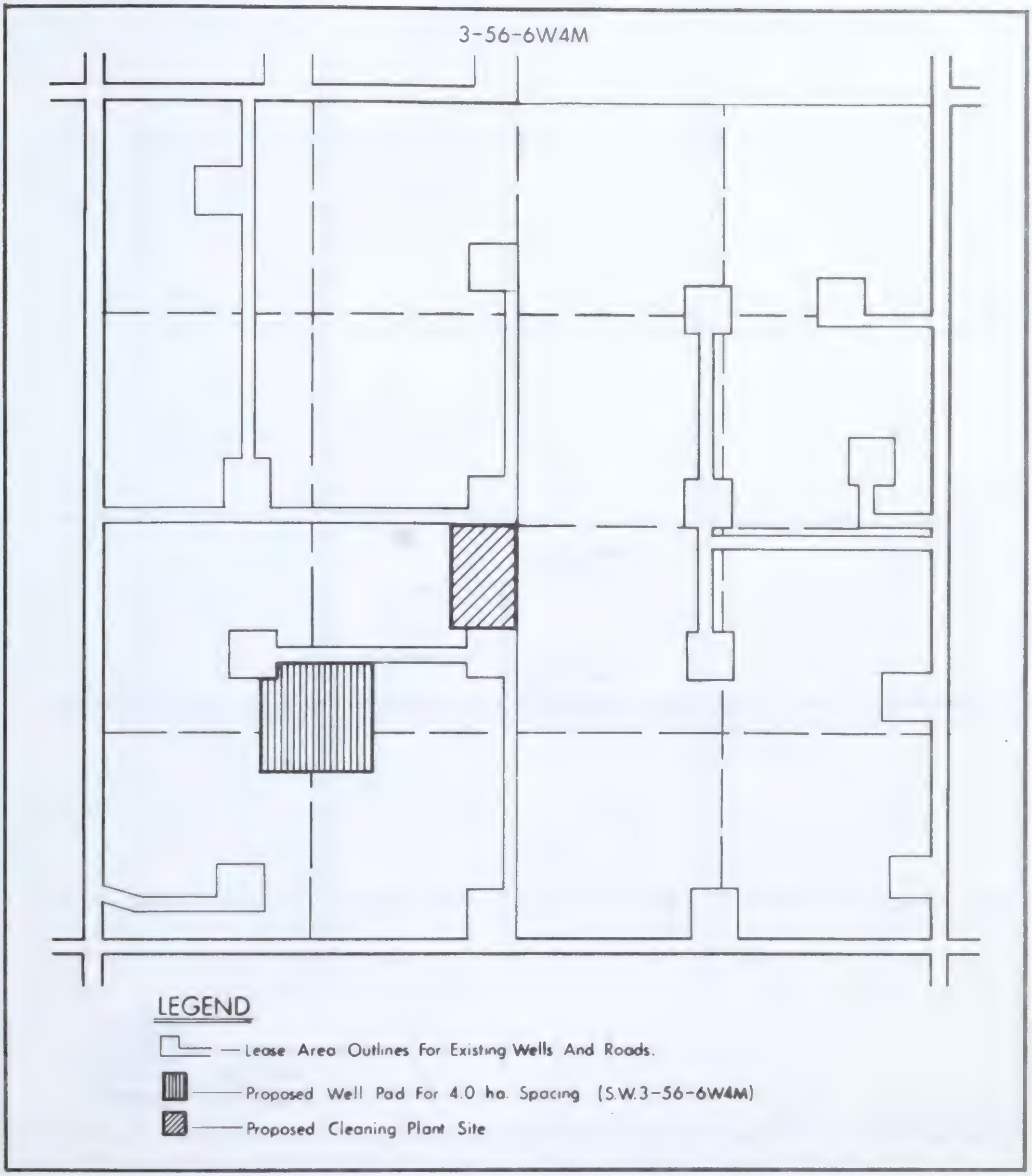


FIGURE 1. SECTION 3-56-6W4M AND PROPOSED SURFACE FACILITY LOCATIONS.

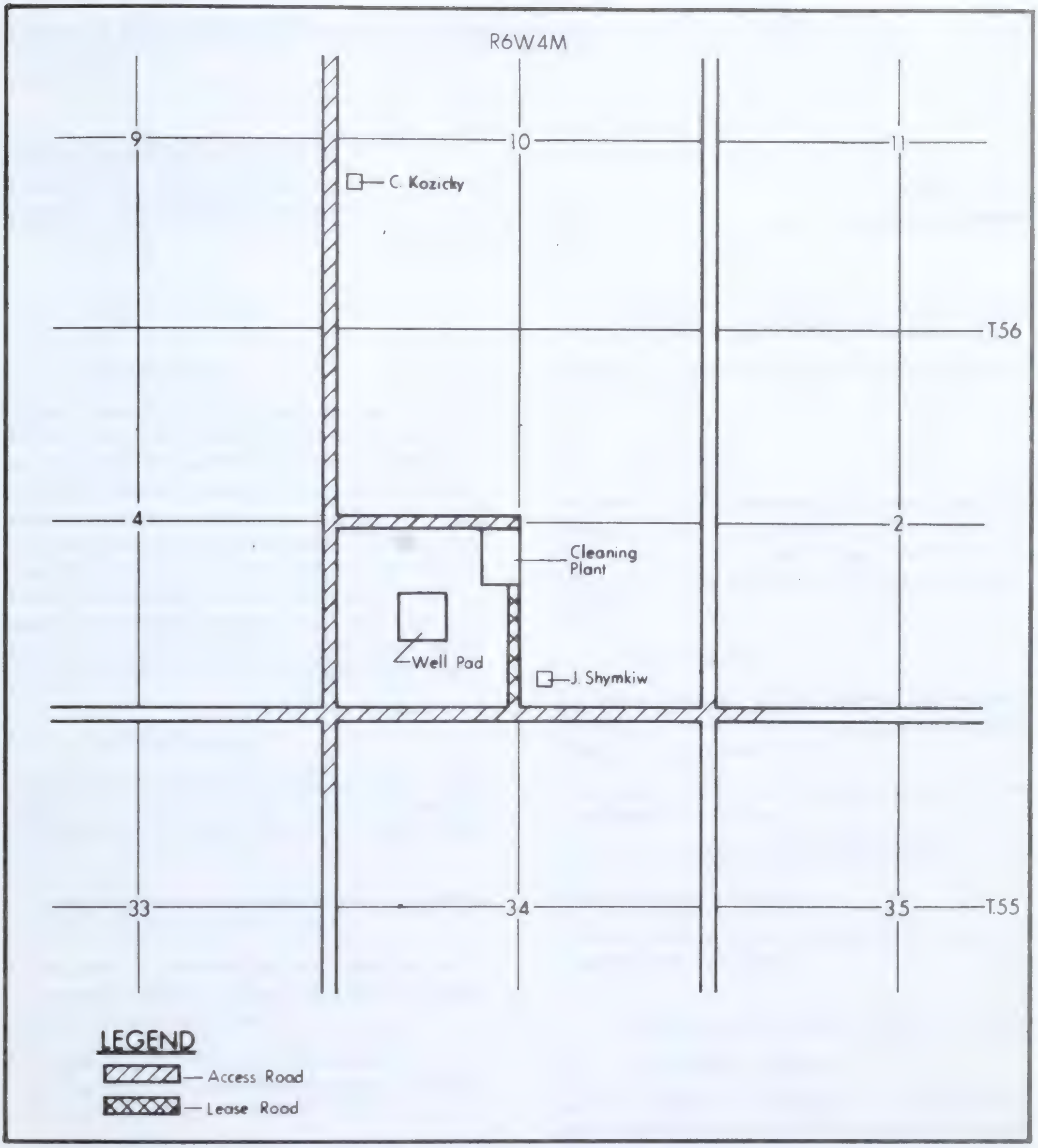


FIGURE 2. SELECTED ROADS AND RESIDENCES

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

DENISON MINES LIMITED ENHANCED RECOVERY MITSUE GILWOOD A POOL

Decision D 85-8
Application 840090

1 INTRODUCTION

1.1 The Application

Denison Mines Limited (Denison), through its agent, Bissett Resource Consultants Ltd., applied pursuant to section 26(a) of the Oil and Gas Conservation Act (Act) for approval of a scheme for enhanced recovery of oil by water injection in part of the Mitsue Gilwood A Pool (the Pool). The general area of the application is shown on the attached figure. Denison proposes to inject fresh water into the well located in legal subdivision 14 of section 22, township 74, range 6, west of the 5th meridian (14-22 well), and to produce from two wells located in Lsd 16-22-74-6 W5M (16-22 well) and Lsd 11-27-74-6 W5M (11-27 well).

1.2 The Interventions

Coseka Resources Limited (Coseka), as operator of the wells in Lsd 2-20-74-5 W5M (2-20 well) and Lsd 2-26-74-6 W5M (2-26 well), filed an intervention stating that:

- Coseka is supportive of the enhanced recovery scheme for the north end of the Mitsue field.
- The scheme as presented does not optimize the use of investment capital or surface land in the Lesser Slave Lake Provincial Park (park).
- Coseka requests the Board to rule that the 14-22 well be designated as the injector for more than one enhanced oil recovery scheme.

Chevron Canada Resources Limited, as operator of the offsetting Mitsue Gilwood Sand Unit #1 (the Unit), intervened in support of the application and for the purposes of cross-examination and advancing argument.

The Department of Recreation and Parks (Parks), as land manager and administrator of the park, intervened at the hearing and stated that:

- Parks did not object to the application.
- It is preferable to have the least possible number of well-located injectors in the park.
- Parks will insist on stringent conditions regarding the surface impact of the well site and its access.
- Parks will strongly recommend subsurface aquifers as a water source.

1.3 The Hearing

The application was considered at a public hearing in Calgary, Alberta, on 11 December 1984, with V. E. Bohme, P.Eng., J. A. Bray, P.Eng., and J. R. Pow, P.Eng., sitting. The participants are listed in the following table.

2 THE ISSUES

The Board concurs with all parties that pressure maintenance is needed in the area and believes the issues relating to the application to be:

- the suitability of the 14-22 well with respect to pressure maintenance in the area,
- the completion interval in the 14-22 well,
- the proposed scheme area, and
- Coseka's request to have water injected on behalf of the 2-20 and 2-26 wells.

3 THE PROPOSED INJECTION LOCATION

3.1 Views of the Applicant

Denison submitted that water injection into the 14-22 well will provide pressure support and ultimately increase recovery within the proposed scheme area and other offsetting lands to the north and east of the injection well, including those containing the 2-26 well.

According to Denison, the Gilwood Sand in the application area was deposited by a major fluvial drainage system during the Middle Devonian Watt Mountain period in two sand zones, A and B, separated by a 2- to 3-metre shale barrier.

In addition, deltaic channel scouring during the deposition of the A sand in certain instances interconnected the upper and lower sands. Channel sand was encountered

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Denison Mines Limited (Denison) K. F. Miller	D. H. D. Barton, P.Eng. D. R. Martin W. K. Brown W. T. Wilson, P.Eng., of Bissett Resource Consultants Ltd.
Coseka Resources Limited (Coseka) E. F. Thurmeier, P.Eng.	E. F. Thurmeier, P.Eng. R. D. Jones, P.Geol. J. R. Stepaniuk, P.Eng.
Chevron Canada Resources Limited (Chevron) D. G. Guest	
Department of Recreation and Parks (Parks) K. R. Erdman	
Energy Resources Conservation Board staff H. R. Hansford A. R. Mustafa J. P. Werth, P.Eng. R. J. Willard, P.Eng.	

by the 14-22 well in the aquifer. Denison believes this channel sand meanders east from the 14-22 well to the 2-26 well, and then turns south through the centre of section 23.

Denison also stated that the 11-27 well and the adjacent unit well in Lsd 10-27-74-6 W5M (10-27 well) contain the A sand, the 16-22 well contains both the A and B sands, and both the 14-22 and 2-26 wells contain the A sand overlying the channel sand.

In addition to the geological evidence, Denison supported its views regarding interzonal communication by examining historical pressure performance of the area. Denison found that the pressure history of the area is consistent, if communication is assumed and if the influence of the distance of wells from the effect of pool production to the south and the pressure support from the flank aquifer to the west are taken into account. In particular, Denison pointed to the high production withdrawals in late 1982 from the 2-26 well and the ensuing rapid pressure depletion in the 10-27 well in 1983 as conclusive evidence of communication between the A sand and the channel sand.

Denison estimated the injective capacity of the 14-22 well to range from 3000 to 9000 cubic metres per month while the proposed scheme would require a maximum of 2100 cubic metres per month. As the injectivity of the 14-22 well was not confirmed by field testing, Denison could not conclude that excess capacity existed in the 14-22 well. If excess injectivity exists, however, Denison concluded that most of the excess would be directed into the channel sand.

3.2 Views of the Interveners

Coseka supported the proposal for injection into the 14-22 well and stated that it would benefit operators in the area. In addition, Coseka submitted that the injectivity of the well appears to be adequate to replace all of Denison's voidage, some portion of the Unit's voidage, and all of Coseka's voidage from the 2-20 and 2-26 wells.

Chevron submitted that the proposed injection in the 14-22 well is the optimum location for providing pressure support to contiguous lands.

3.3 Views of the Board

The Board agrees with the applicant and interveners that the 14-22 well is an optimum location for water injection to effect pressure maintenance in the northern end of the Pool. The Board notes that the 14-22 well encountered the aquifer slightly below the oil-water contact. Water injection should therefore result in favourable flood sweep and minimize trapped oil losses.

The Board has reviewed the geological and pressure data and concludes that communication exists between the A and channel sands in the area.

The Board understands that the injectivity of the 14-22 well is subject to some degree of uncertainty which can

be resolved only through appropriate injectivity well tests. The Board is of the opinion that, on the basis of theoretical estimates of injectivity and the performance of existing injectors within the Pool, the 14-22 well should be capable of replacing the voidage of the proposed scheme as well as some offset producers.

4 THE COMPLETION INTERVAL OF THE 14-22 WELL

4.1 Views of the Applicant

Denison indicated its intention to complete the 14-22 well in both the A sand and the channel sand. In the event of inadequate pressure support in the 11-27 well, Denison stated that it would consider plugging back the lower set of perforations in the channel sand.

4.2 Views of the Interveners

Coseka submitted that Denison had no production capability in the channel sand and therefore the zone of injection in the 14-22 well should be restricted to the A zone.

4.3 Views of the Board

The Board concurs with the applicant's proposed completions and contingency plan for the 14-22 well. Given that the A sand and channel sand appear to be in communication, the Board can see no value in restricting the completion of the 14-22 well to the A sand. In the event that pressure maintenance is not occurring, either due to a lack of communication between zones or due to the channel sand acting as a thief zone for the injected water, the Board believes that confining injection to the the A sand may provide an appropriate solution.

5 THE PROPOSED SCHEME AREA

5.1 Views of the Applicant

Denison proposed a scheme area consisting of the east half and northwest quarter of section 22, the west half of section 27, and the northeast quarter of section 28-74-6 W5M.

With respect to the southeast quarter of section 22, Denison stated that it did not intend to drill in the quarter since it believed the reserves would drain to the 16-22 wellbore during the duration of the waterflood. Denison acknowledged that the extent of reserves in the southeast quarter of section 22 was questionable.

Denison supported the inclusion of the northeast quarter of section 22, which contains the 16-22 well, in the scheme area. Denison confirmed that the 16-22 well had demonstrated low productivity at high water-oil ratios but believed the rates to be sustainable. Denison also stated that incremental recovery of the quarter section reserves would occur through the 16-22 wellbore due to the proposed scheme.

The northwest quarter of section 22 contains the 14-22 well, which Denison agreed should be included in the scheme with zero acreage assigned for reserves and project allowable purposes.

Denison stated that it was assessing the possibility of drilling in the southwest quarter of section 27 but had no definite plans.

5.2 Views of the Board

In determining the appropriate lands to be designated as part of the scheme, the Board has followed the criteria set out in sections 5.070 and 5.160 of the Oil and Gas Conservation Regulations (Regulations). In accordance with these criteria, the Board would establish the scheme area to include the north half of section 22 and the west half of section 27. The 14-22 well would be included with zero acreage assigned for reserve purposes. The northeast quarter of section 28 and the southeast quarter of section 22 do not contain productive wells and in the opinion of the Board would not contribute to the ultimate scheme recovery. Therefore, the Board is not prepared to include these drilling spacing units within the scheme area.

6 THE DESIGNATION OF THE 14-22 WELL AS AN INJECTOR FOR MORE THAN ONE SCHEME

6.1 Views of the Applicant

Denison submitted that it would be unfair and wrong in law for the Board to impose on Denison an obligation to allow Coseka to use the 14-22 well as an injector for its purposes. According to Denison, it would be equally unfair and wrong in law to withhold Board approval of the application for the purpose of inducing negotiations between Denison and Coseka. The applicant viewed both above actions as tantamount to compulsory unitization and noted that such legislation has not been enacted.

Denison stated that approval of the application would not preclude the possibility of the formation of other enhanced recovery schemes in the north end of the Pool which may include Denison lands. Denison also stated that should surplus injectivity be proven, it would consider injection on behalf of other parties following appropriate agreements. In this regard, Denison submitted that it would be easier for Denison to accommodate the Unit's flood requirements than Coseka's, as the Unit lands directly offset the proposed scheme and lie between the scheme and Coseka lands.

6.2 Views of the Interveners

Coseka submitted that the 14-22 well would provide sufficient injectivity to maintain pressure in the area of the

Pool that includes its lands and requested that Board approval of the application be made conditional on the designation of the 14-22 well as a multi-scheme injector. In Coseka's view, such a condition would prevent unnecessary capital expenditure by duplication of injection facilities and would minimize surface impact within the park.

Coseka stated that the use of the 14-22 well for injection to replace voidage from its 2-20 and 2-26 wells would be the optimum solution to pressure maintaining its lands. To this end, Coseka had entered into negotiations with Denison for the use of the 14-22 well. According to Coseka, another alternative would be a competitive scheme involving voidage replacement in a directionally drilled injector in the southeast quarter of section 28-74-6 W5M. Coseka stated that it had initiated preliminary discussions with Parks for the use of a surface location in Lsd 7-27-74-6 W5M for this purpose. Coseka estimated the cost of the additional injector at $750 000. The least desirable alternative, Coseka maintained, would involve joining the Unit. Coseka placed the unitization alternative as its lowest preference because of the large unresolved difference between the participation factors offered by the Unit and those proposed by Coseka.

In summary, Coseka maintained that a Board approval of the application would be detrimental to its negotiations with Denison as it perceived that such an action would remove Denison's incentive to negotiate.

In Chevron's view, the environmental considerations of the scheme are properly the subject matter of the Minister of Environment. Chevron further submitted that Coseka's request to designate the 14-22 well as a multi-scheme injector amounts to compulsory unitization, which is not provided for in the Act or Regulations.

Parks expressed its understanding that operators in the area are aware of its concerns regarding land use in the park, particularly with respect to beach impact. Parks would prefer the least number of injectors as possible but does not object to Board approval of the subject application.

6.3 Views of the Board

The Board is not prepared to approve the Coseka request to designate the 14-22 well a multi-scheme injector, since it would force what would normally be a commercial arrangement on Denison without any prior agreement between the parties. In addition, the Board does not believe it has the jurisdiction to act on Coseka's request and therefore is not prepared to condition an approval in the manner requested by Coseka.

The Board notes that Coseka has proposed a number of alternatives that would result in pressure maintenance of its lands. In the Board's view, however, the alternatives of either unitization or "injection on behalf of" other schemes are clearly more favourable than the duplication of existing facilities inherent in competitive schemes. As stated in Decision D 84-4, the Board views schemes of this nature as an unfortunate but necessary choice in the absence of more favourable alternatives. In addition, the Board assumes that in the interest of overall pool conservation, Denison would make any excess injection capacity available to other Pool operators in the vicinity.

7 CONCLUSIONS

The Board, having duly considered the submissions and evidence of the applicant and interveners, has reached the following conclusions:

- There is a need for pressure maintenance in the part of the Pool encompassed by the area of application.
- The 14-22 well represents the optimum location for water injection.
- The proposed scheme will not adversely affect offsetting mineral owners or Pool operators.
- The proposed completion interval in the 14-22 well is appropriate.
- The proposed scheme area should comprise the north half of section 22and the west half of section 27-74-6 W5M, with zero acreage being assigned to the 14-22 well for reserves purposes.

8 DECISION

The Board grants Application 840090 by Denison Mines Limited for an enhanced recovery scheme in part of the Mitsue Gilwood A Pool. The appropriate performance conditions and scheme area will be made part of the Board approval.

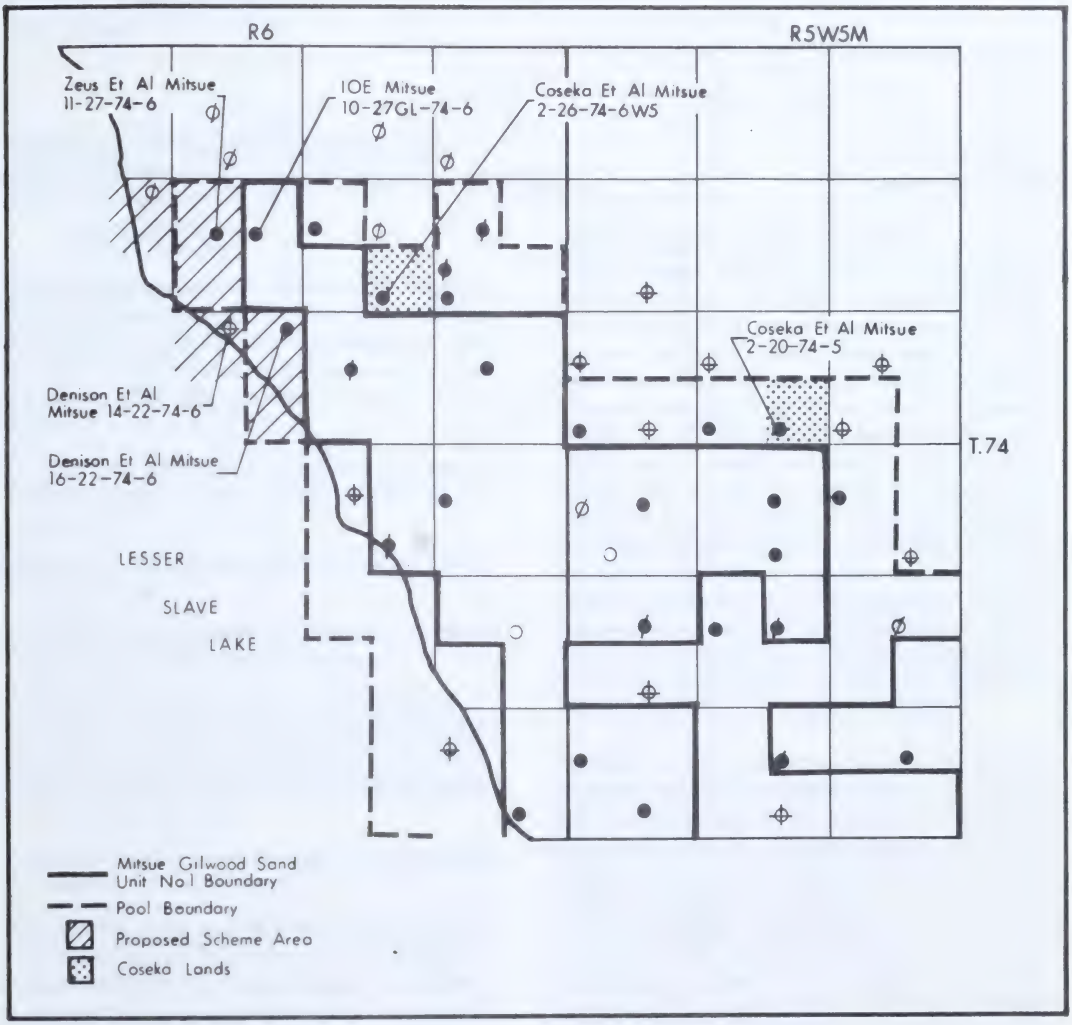
DATED at Calgary, Alberta, on 13 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

J. A. Bray, P.Eng.
Acting Board Member

J. R. Pow, P.Eng.
Acting Board Member



MITSUE GILWOOD A POOL   Application 840090

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

CONSOLIGAS MANAGEMENT LTD. APPLICATION FOR GAS REMOVAL PERMIT

Decision D 85-9
Application 840886

1 APPLICATION

ConsoliGas Management Ltd. (ConsoliGas) applied to the Energy Resources Conservation Board (Board), pursuant to section 2 of the Gas Resources Preservation Act (the Act), for a permit authorizing the removal of gas from Alberta. The applicant sought a permit which would:

- provide for the removal of 211.34 million cubic metres (10^6 m^3) of gas, in total, during the term of the permit,
- provide for the maximum annual removal of 70.445 x 10^6 m^3 of gas,
- provide for the maximum daily removal of 253.7 thousand cubic metres (10^3 m^3) of gas,
- provide for a three-year permit term commencing on the date on which the approving Order in Council is signed by the Lieutenant Governor in Council, or such lesser term as may be necessary to terminate the permit on 31 October 1988, and
- name certain fields from which gas may be obtained for removal from the province.

ConsoliGas is a federally incorporated company formed to acquire gas supplies in Western Canada for delivery to industrial consumers in Eastern Canada. The applied-for gas volumes would be purchased at a meter station in legal subdivision 1 of section 32, township 59, range 13, west of the 4th meridian, from a group of nine producers headed by Brenda Mines Limited (Brenda). Approximately 39 per cent of the gas proposed for removal from Alberta would be supplied by Brenda and a sister company, Heath Steel Oil and Gas (Heath). Gas reserves would be obtained from the Ashmont, Clay, Corrin, Craigend, Stry, and Whitford fields, and from three wells in presently unnamed fields.

ConsoliGas stated that it would arrange for transportation of the gas through the pipeline facilities of NOVA, AN ALBERTA CORPORATION (NOVA) to a point near Empress, where portions would be sold to Le Gaz Provincial Du Nord de Québec Ltée (Le Gaz), and to Consumers' Gas Company Ltd. (Consumers'). Both Le Gaz and Consumers' would arrange for transportation through the facilities of TransCanada PipeLines Limited (TransCanada) to their own facilities, or those of their affiliates, in Ontario and Quebec. Le Gaz would deliver its volume to Noranda Inc., (Noranda) Horne Division, for use as fuel in the Noranda copper concentrator and smelter located at Rouyn/Noranda, Quebec. Noranda is the parent company of Brenda and Heath. Consumers' would deliver the volume it purchased to the Cyanamid Canada, Inc. (Cyanamid) ammonia fertilizer plant near Niagara Falls, Ontario. ConsoliGas also stated at the hearing that the original intention of Noranda to negotiate an ammonia manufacturing arrangement with Nitrochem Inc. at Brockville, Ontario, had been changed to that of a similar arrangement with C-I-L Agricultural Chemicals at its Lambton Works in Courtwright, Ontario, on the Union Gas (Union) system. The ammonia would then be used for the manufacture of phosphate fertilizer at Noranda's Belledune, New Brunswick plant.

Interventions were submitted by The Independent Petroleum Association of Canada (IPAC), TransCanada, Pan-Alberta Gas Ltd. (Pan-Alberta), Cyanamid, and Consumers'. IPAC did not oppose the application but suggested that it should be denied or deferred if inequities to other gas producers occurred as a result of the proposed gas sales. TransCanada submitted that the application should be denied. Consumers' stated at the hearing that there were no firm arrangements to transport the gas to the Cyanamid or C-I-L plants, and that it would be premature for the Board to issue a permit for the volumes allocated to the ammonia component of the application.

2 HEARING

The application was heard by the Board at a public hearing held in Calgary, Alberta, on 15 and 16 January 1985, with V. Millard, H. A. Antonio, P.Eng., and E. R. Brushett, P.Eng., sitting. A table of those who appeared at the hearing is presented in this report.

3 BACKGROUND

The application was registered on 28 August 1984 and advertised for objections on 31 October 1984. On

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
ConsoliGas Management Ltd. (ConsoliGas) K. F. Miller S. F. McAllister	W. J. Demcoe, C.A. D. G. Snyder, P.Eng. J. Ballaban, P.Eng. R. Gendre, P.Eng. J. A. Bolter, P.Geol.
Cyanamid Canada Inc. (Cyanamid) D. A. Holgate E. A. Christie	
The Consumers' Gas Company Ltd. (Consumers') J. H. Farrell	
Independent Petroleum Association of Canada (IPAC) J. P. Peacock, Q.C.	A. P. Markin, P.Eng. R. B. Hillary R. G. DeWolf, P.Eng.
Pan-Alberta Gas Ltd. (Pan-Alberta) D. A. Dawson	
TransCanada PipeLines Limited (TransCanada) E.W.H. Mallabone	
Energy Resources Conservation Board staff A. A. Gervais J. W. Newton K. Johnston M. E. Mumby	

16 November 1984, TransCanada filed an objection stating that the Board should hold a public hearing in respect of Application 840886. During the period of notice between 31 October 1984 and 16 November 1984, the Legislative Assembly of Alberta enacted a new Gas Resources Preservation Act, to which Royal Assent was given on 13 November 1984. The new Act modified the requirements that must be satisfied before gas can be removed from the province. Specifically, section 5(3)(c) of the new Act requires the Board to have regard for the expected economic costs and benefits to Alberta of any proposed removal of gas from Alberta.

A notice of hearing was published on 19 December 1984 scheduling a hearing to be held in Calgary on 15 and 16 January 1985.

4 ISSUES

The new Gas Resources Preservation Act directs that the Board can only approve the removal of gas from the province if it is in the public interest, having regard for

(a) the present and future needs of persons in Alberta,

(b) the established reserves and the trends in growth and discovery of reserves of gas or propane in Alberta, and

(c) the expected economic costs and benefits to Alberta of the removal of the gas or propane from Alberta.

The Board has historically interpreted the first two considerations as requiring it to determine whether the gas proposed for removal is surplus to Alberta's requirements. The third consideration, which is a new provision, requires the Board to determine whether the economic costs and benefits of the proposed removal would be in Alberta's public interest.

The Board concludes, therefore, that the issues are

(a) Is the gas proposed for removal, surplus to Alberta's requirements?

(b) Would the economic costs and benefits of the proposed removal be in the Alberta public interest?

5 IS THE GAS SURPLUS TO ALBERTA'S REQUIREMENTS?

5.1 Views of the Applicant

ConsoliGas contended that the applied-for volumes are surplus to Alberta's requirements. None of the interveners contested that position.

5.2 Views of the Board

The Board's estimate of reserves under the applicant's control with respect to this application is 587 x 10^6 m^3, some 376 x 10^6 m^3 more than the total amount for which the removal permit is requested. A portion of the gas would be available from fields named in Pan-Alberta removal Permit PA 81-4, and these volumes have been released in a 20 October 1983 letter agreement between Pan-Alberta and Brenda. The remainder would be supplied from previously uncontracted lands.

Having regard for the small volume of gas proposed to be removed and the current gas reserves in Alberta, the Board agrees with the applicant that the gas is surplus to Alberta requirements. The Board is also satisfied that sufficient deliverability will be available from wells presently tied in and from potential new wells in the ConsoliGas-controlled lands to meet the needs of the removal permit applied for by ConsoliGas.

6 ARE THE ECONOMIC COSTS AND BENEFITS IN THE ALBERTA PUBLIC INTEREST?

6.1 Introduction

ConsoliGas filed its application in August, 1984; the Board advertised for objections at the end of October, 1984; and an objection was received on 16 November 1984. The new Gas Resources Preservation Act was given Royal Assent on 13 November 1984. While the application did not provide estimates of economic costs or benefits because it had been filed prior to the new provisions, the Board decided to proceed directly to a public hearing in view of the unique circumstances.

At the hearing the applicant and interveners identified several potential costs and benefits but did not quantify them. While many of the costs and benefits identified are difficult to quantify, the fundamental question is whether or not the proposed removals would represent additional deliveries of Alberta gas or whether they would only result in the replacement of one Alberta producer by another producer. The question of "incrementality" was discussed extensively at the hearing and several definitions of an incremental sale were offered. The Board believes that an incremental sale is one that would only occur if the applied-for removal permit were issued.

6.2 Views of the Applicant

ConsoliGas contended that approval of its application would permit the sale of Alberta gas to industrial consumers in Ontario and Quebec. More specifically, it would permit Noranda to continue to use Alberta gas that is currently purchased from TransCanada as interruptible gas, and to substitute gas for its current purchases of heavy fuel oil. In a similar manner, approval would permit the continued use of Alberta gas at Ontario plants for the manufacture of ammonia to be delivered to Noranda's Belledune plant in New Brunswick.

ConsoliGas indicated that if the application were denied, Noranda could cease purchasing interruptible gas from TransCanada for its smelting operations and instead utilize heavy fuel oil. Similarly, Noranda could discontinue the manufacture of ammonia in Ontario plants and instead purchase the product off shore.

In responding to questions respecting why the gas deliveries would only occur if the application were approved, the applicant stated that Noranda's ownership of Brenda and Heath, which would supply much of the gas, resulted in a lower net cost to the plant, thus making the proposed deliveries of gas favourably priced in comparison to fuel oil supplies.

ConsoliGas contended that since the sales that would follow from approval of the application were incremental, no other producers would be adversely affected and there would be significant net benefits. ConsoliGas agreed that if the sales were not incremental there would not be any net benefits.

6.3 Views of the Interveners

TransCanada contended that the proposed deliveries were not incremental and that approval of the application would only result in a reduction in production for a large number of producers delivering gas to TransCanada.

IPAC expressed concerns because the arrangements were direct sales and questioned whether the sales would actually be incremental. It indicated that there was insufficient evidence to demonstrate that sales would in fact be incremental and argued that even if they were, there were costs to other Alberta producers by permitting direct sales between producers and consumers. IPAC contended that since several energy programs and policies had been established on the basis of participation by all producers, special marketing arrangements, such as that proposed by ConsoliGas, result in net costs to other producers. Specific reference was made to:

(a) Natural Gas Market Incentive Program (NGMIP)

(b) Market Development Incentive Program (MDIP)

(c) Export Flowback

(d) Transportation Costs.

6.4 Views of the Board

The Board agrees with the contention that unless the gas to be removed from the province under an applied-for permit will serve a market that is incremental to markets already being supplied by Alberta gas, approval of the application will not provide net economic benefits to Alberta. If the markets are incremental, then total revenues would increase and the revenues to other producers would not be affected.

IPAC expressed concerns about direct sales, particularly in relation to Canadian markets and the impact of those sales on other producers through the administration of several energy programs and policies.

With respect to the question of direct sales, the Board believes the important issue is the incrementality of the sale. If the proposed sale is incremental, it would appear to make little difference whether it is made directly between the producer and end consumer or through an intermediate purchaser, providing the sales price is appropriate. With respect to the alleged impacts of such sales on other producers, the Board is not convinced that one type of sale should be singled out for special assessment but, in any event, the extent that other producers might be affected under each of the energy programs by approval of the application should be recognized in assessing the economic costs and benefits.

As the Board sees it, the basic question that needs to be addressed respecting net benefits is whether the proposed sales would be incremental. The Board believes that for a sale to be incremental it must represent a delivery that would not otherwise occur. The definition would include both a delivery to a totally new market and the retention of an existing market that would otherwise be lost. While it may be relatively simple to state the principle, it is difficult to reach a conclusion as to whether or not a proposed sale will, in fact, be incremental. In order to be completely satisfied about that question, one needs to know what those persons making the decision under the alternate circumstances would likely decide. That, of course, is not possible.

In the ConsoliGas case, the applicant stated that one of the purposes of the proposed delivery would be to enable Noranda to substitute gas for fuel oil at its copper smelter, thereby providing incremental deliveries of Alberta gas. Another purpose would be to preserve markets that currently exist in the form of interruptible gas purchases for the smelting operations and gas used in the manufacture of ammonia for its Belledune plant. Noranda indicated that if the application were not granted, then those existing gas deliveries might cease and, therefore, preserving those markets would ensure incremental deliveries. However, it did not provide any detailed energy cost data or other calculations to support its position, but instead relied on a general description of economic circumstances. When questioned about detailed cost data, it declined to answer because it considered disclosure of the data could harm its competitive position.

While the interveners either questioned or disagreed with the applicant's contention that the deliveries would be incremental, they also did not present any energy cost data to support their position.

After carefully considering the application, the Board agrees that the substitution of fuel oil by gas at the Noranda smelter would provide a new market for Alberta gas. The Board believes that the substitution would not likely occur if the application were denied and, therefore, that portion of the proposed removal would result in incremental deliveries of Alberta gas.

With respect to the remaining portion of the gas, which the applicant contended would be used to "preserve" existing markets, the Board accepts that such might be the case, but there is little evidence to substantiate it. Having regard for the Board's responsibilities under the new statute respecting "the expected economic costs and benefits to Alberta", the Board believes that where a proposed removal would only preserve existing markets, there must be sufficient evidence to show that denial of the application would lead to reduced deliveries. The applicant declined to answer questions related to that issue and presented little evidence to support its contentions. As a consequence, the Board does not have sufficient evidence to satisfy it that the use of interruptible gas for the smelting operations or gas used for the manufacture of ammonia would be reduced or discontinued if the application were denied. The Board is not, therefore, able to conclude that those deliveries would be incremental.

The Board has examined the expected costs and benefits to Alberta if the proposed removal were approved. For that portion of the application that would result in incremental deliveries of Alberta gas, the benefits would be substantially greater than the costs. The annual benefit for the incremental gas deliveries to the Horne Division Plant for substitution of fuel oil would be some 3 to 4 million dollars based on the current Alberta Border Price. The related costs would mainly arise from expenditures by the producing industry in Alberta for market expansion programs outside the province. To the extent that those programs are successful, there would be corresponding benefits to the producers. It is worth noting,

however, that the 28 March 1985 energy pricing agreement between the western provinces and the federal government (the Western Accord) allows for NGMIP and MDIP payments only up to 30 April 1986, and consequently, any costs that might be attributed to those programs would be eliminated beyond that date.

The estimate of benefits is based on revenues from gas sales in accordance with the Alberta Border Price which might be discontinued in the future. The gas purchase contract filed by ConsoliGas does not allow for that eventuality and only makes reference to the Alberta Border Price. Consequently, it is not possible for the Board to determine the gas purchase price if the Alberta Border Price were to be discontinued, nor to estimate the benefits that would accrue to the province through approval of the application. The Board believes that deficiency should be corrected if a permit were to be issued.

For that portion of the application that the Board concludes would not result in incremental deliveries, the costs exceed the benefits. That is due to the fact that the incremental revenues received by the producer companies named in the application are offset by reduced revenues to other producers. Therefore, the incremental costs incurred in placing new facilities on production and other costs are not offset and the overall result is negative.

In summary, the Board agrees that the portion of the proposed removal permit that would be used to displace fuel oil at the Noranda smelter would result in incremental deliveries of Alberta gas and that as long as the Alberta Border Price remains in effect, approval of the application would provide net benefits to the province. Since those benefits are dependent on the substitution actually taking place, the Board believes that any permit issued to the applicant should be subject to the following condition:

> "The Permittee shall satisfy the Board at the end of three months following the commencement of gas removal and annually thereafter, that gas deliveries made under the permit have resulted in the substitution of gas for fuel oil at the Noranda smelter."

In order to ensure that the removal would provide net benefits to the province should the Alberta Border Price be discontinued, the Board believes that any permit issued to the applicant should be subject to the following conditions:

> "In the event that the Alberta Border Price ceases to exist, the permit shall be suspended until the Permittee has filed a copy of the gas purchase contract specifying the purchase price for the gas and until the Board has advised the Permittee in writing that the removal of the gas at the specified purchase price will continue to be in the public interest of Alberta within the meaning of subsection 5(3) of the Act.

> "The Permittee shall, promptly upon the execution thereof, file a copy of any document which changes the purchase price specified in the gas purchase contract and this filing requirement shall apply to each successive change in the purchase price for the gas."

7 DECISION

In light of its findings and responsibilities under the Act, the Board, with the approval of the Lieutenant Governor in Council, is prepared to grant a gas removal permit to ConsoliGas for gas to be used in substitution of fuel oil. The proposed permit would be in the form shown in Appendix A and would be subject to the terms and conditions therein contained as well as any conditions imposed by the Lieutenant Governor in Council.

DATED at Calgary, Alberta, on 7 May 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

H. A. Antonio, P.Eng.
Acting Board Member

E. R. Brushett, P.Eng.
Acting Board Member

APPENDIX A
FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to ConsoliGas Management Ltd. authorizing the removal of gas from the Province

PERMIT NO. CG 85-1

WHEREAS ConsoliGas Management Ltd. has applied in Application No. 840886 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that the applicant is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council numbered O.C. and dated .

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to ConsoliGas Management Ltd. (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a three-year term commencing on the date hereof, provided that such term shall not extend beyond 31 October 1988.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 109 893 000 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 140 900 cubic metres and in a 12-month period such rates shall not exceed 36 631 000 cubic metres.

3. Notwithstanding clause 2, subclause (b), the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Ashmont Field	Craigend Field
Clay Field and Area	Stry Field
Corrin Field	Whitford Field

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1), shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipeline of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. The Permittee shall satisfy the Board at the end of three months following the commencement of gas removal and annually thereafter, that gas deliveries made under the permit have resulted in the substitution of gas for fuel oil at the Noranda smelter.

9. In the event that the Alberta Border Price ceases to exist, the permit shall be suspended until the Permittee has filed a copy of the gas purchase contract specifying the purchase price for the gas and until the Board has advised the Permittee in writing that the removal of the gas at the specified purchase price will continue to be in the public interest of Alberta within the meaning of subsection 5(3) of the Act.

10. The Permittee shall, promptly upon the execution thereof, file a copy of any document which changes the purchase price specified in the gas purchase contract and this filing requirement shall apply to each successive change in the purchase price for the gas.

11. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

12. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

13. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION, at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

14. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 13 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

15. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this .

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BRAZEAU RIVER NISKU CARBONATE BANK OPTIMUM DEPLETION INQUIRY AMOCO CANADA PETROLEUM COMPANY LTD.

Decision D 85-10
Proceeding 840350
Application 840147

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1 INTRODUCTION

The Carbonate Bank of the Nisku Formation is an extensive northeast-southwest trending reef/basin complex of Upper Devonian age. Hydrocarbons are found in a porous dolomite facies known as the Zeta Lake member. Reservoir rock is found in both isolated offshore pinnacle reefs and the leading edge of the Carbonate Bank. The boundary between sealing basin shales and the porous dolomite bank can be reasonably well defined by seismic interpretation. The southwest limit of the porous bank deposit is defined by the tight, lagoonal carbonate facies called the Dismal Creek member. This limit cannot be accurately defined by seismic interpretation leading to difficulties in determining the extent of communicating reservoir rock.

The Carbonate Bank in the Brazeau River Field contains a gas condensate fluid having potential for enhancement of liquid hydrocarbon recovery by dry gas cycling. Amoco Canada Petroleum Company Ltd. (Amoco) requested approval of a scheme of dry gas cycling in a portion of the Carbonate Bank. Amoco proposed dry gas injection at the well located at legal subdivision (Lsd) 10-2-48-12 W5M (10-2 well) with raw gas production from the wells located at Lsd 7-34-47-12 W5M (7-34 well), Lsd 7-10-48-12 W5M (7-10 well), and Lsd 13-12-48-12 W5M (13-12 well). Although the proposal involved wells operated by Petro-Canada Inc. (Petro-Canada) and Dome Petroleum Limited (Dome), these companies did not support the Amoco application. There was a high degree of interest in gas cycling among all the area operators but differing concepts existed as to how and when cycling might be implemented. These differing concepts evolved from varying interpretations of pool configurations, reservoir transmissibilities, fluid properties, and potential economic advantages. The Energy Resources Conservation Board (Board) therefore initiated an inquiry into the optimum depletion strategy for the recovery of hydrocarbons from the Carbonate Bank. Amoco's cycling application was to be heard concurrently with the inquiry.

2 BOARD FINDINGS AND DECISION

2.1 Findings

The Board concludes that a gas cycling scheme is required to enhance recovery of liquid hydrocarbons in the seven wells in pressure communication (main pool area) of the Carbonate Bank. A scheme of full voidage replacement above the dew point is judged to be the optimum strategy from the standpoint of liquid recovery given the evidence that partial voidage replacement could result in significant losses of liquid and the remaining uncertainties regarding extent of reserves and potential drilling. It notes that pools in the Brazeau River Field containing reservoir fluids similar in retrograde nature to that found in the Carbonate Bank have employed this method of depletion.

The Board considers the representative dew point of the main pool area to be 27 300 kilopascals (kPa) and believes that a pressure margin of 1500 kPa would be adequate for the operation of the cycling scheme. Further, the choice of depletion method above the operating pressure should have no effect on hydrocarbon liquid recovery in these circumstances. The Board therefore believes that primary production may be continued to the operating pressure of 28 800 kPa, and that this primary production will expedite further reservoir information for the assessment of the extent of reserves.

The Board concludes that unitization of the main pool area is desirable prior to cycling to ensure the economic, orderly, and efficient depletion of the pool. It understands that significant flexibility exists for processing facilities for the cycling scheme, and is confident that the operators can achieve a mutually satisfactory arrangement in conjunction with unitization or equivalent operating agreements.

Regarding the rest of the Carbonate Bank, the Board believes that further potential exists for cycling in the wells located at Lsd 10-25-47-12 W5M (10-25 well) and Lsd 02/6-29-47-11 W5M (6-29 well), and also in the wells located at Lsd 2-11-48-13 W5M (2-11 well) and Lsd 2-12-48-13 W5M (2-12 well). The Board notes that further testing and analyses will be necessary for these wells. This data should be acquired so as to permit adequate time for analysis prior to applications for cycling approval. The Board considers the initial restraint of not producing below the dew point to be still applicable to wells not included in the main pool area.

2.2 Decision

Interim Decision D 84-30 approved the principle of gas cycling in the 7-well main pool area. The Board has decided that primary production to a built-up pressure of 28 800 kPa followed by a scheme of gas cycling with full voidage replacement represents the optimum mode of depletion for recovery of liquid hydrocarbons from the main pool area. The Board notes resolution of the following matters is required prior to approval of a cycling scheme:

- approval area,
- gas injection location in the 7-10 area,
- cycling rates and utilization of facilities, and
- completion of unitization or equivalent operating agreements.

The necessary cycling approval will be issued by the Board's Gas Department after an acceptable cycling

application, pursuant to section 26 of the Oil and Gas Conservation Act, is made by the operator or operators of the project.

The reasons for the decision are detailed in the remainder of this report.

DATED at Calgary, Alberta, on 14 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman, P.Eng.
Board Member

J. A. Bray, P.Eng.
Acting Board Member

3 BACKGROUND

3.1 Development History

The Carbonate Bank was first encountered by the 7-34 well in 1977 and presently 12 wells have penetrated the Carbonate Bank. During the 1982 drilling of the twelfth well, 13-12, the well blew out of control for 68 days. Reservoir voidage created by the uncontrolled flow provided evidence of some degree of pressure communication among several wells in the area. Table 1 lists the wells comprising the Carbonate Bank and the operators of those respective wells.

In a series of decisions as listed in Table 2, the Board approved the following facilities for development of the gas reserves in the area:

- processing facilities proposed by Hudson's Bay Oil and Gas CompanyLimited (HBOG) located at Lsd 6-10-47-14 W5M (West Pembina plant)and the associated gas gathering system. The West Pembina plant commenced operations in June 1984;
- processing facilities proposed by Petro-Canada located at Lsd 4-31-48-12 W5M (Brazeau River plant) and the associated gas gathering system. The Brazeau River plant is scheduled for start-up in April 1985; and
- Amoco pipeline to connect the 7-10 well to the HBOG gathering system at the 7-34 well for production of the 7-10 well to the West Pembina plant prior to start-up of the Brazeau River plant. The pipeline is scheduled for construction during the first quarter of 1985.

Figure 1 illustrates the processing and gathering facilities for the area.

3.2 Primary Production Restraints

Early fluid analyses from Carbonate Bank wells indicated that the wells were candidates for dry gas cycling. In light of the progressive development of processing and gathering facilities in the area and the lack of definitive reservoir information, the Board imposed restraints on production from some Carbonate Bank wells for which gathering systems were proposed. The restraints allowed for primary production subject to the operator of the well undertaking to determine the dew point pressure of the reservoir fluid and not producing below that pressure prior to establishing the optimum depletion scheme for conservation of hydrocarbons. This restraint was imposed on the 7-34 well in Decision D 83-11, and later on the 7-10 well and the well located at Lsd 3-20-48-12 W5M (3-20 well) in Decision D 83-29. By letter dated 18 December 1983 to the major operators in the Brazeau River Field, the Board urged that these restraints be considered for all wells in the Carbonate Bank thought to have potential for cycling.

3.3 Application 840147 and Proceeding 840350

By Application 840147 dated 8 February 1984, Amoco requested approval of a scheme of dry gas cycling in a portion of the Carbonate Bank. Although there was a high degree of interest in gas cycling among all the area operators, differing concepts existed as to how and when cycling might be implemented. The Board therefore initiated Proceeding 840350 for an inquiry into the optimum depletion strategy for the recovery of hydrocarbons from the Carbonate Bank. Application 840147 was to be heard concurrently with Proceeding 840350.

3.4 Opening of the Inquiry and Hearing

The inquiry and hearing was opened on 25 June 1984 before a division of the Board comprised of V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and J. A. Bray, P.Eng. Submissions to the proceedings were made by Amoco, Petro-Canada, Dome, and Texaco Canada Resources Ltd. (Texaco). The submissions indicated a wide range of interpretations regarding reservoir fluid dew point pressures, pool configurations, reservoir transmissibilities, and overall depletion strategies. At the opening of the hearing, the parties advised the Board that they had agreed to a joint testing program designed to resolve some of the major uncertainties in the reservoir. The testing program involved production, pressure, and fluid testing in nine wells. The inquiry and hearing was therefore adjourned pending the results of that program.

The program allowed for, among other things, primary production from the Dome 7-34 well for a 2-month period followed by a 1-month shut-in. The testing program as proposed indicated a possibility for extended production from the 7-34 well following the 1-month shut-in. Both Petro-Canada and Amoco requested some form of restriction on extended production from the 7-34 well.

In its Memorandum of Decision dated 18 July 1984, the Board concluded that, due to the communication of the 7-34 well with other wells exhibiting higher dew point pressures, further restraints on primary production were necessary in the absence of the testing program results. The Board therefore restricted production of the 7-34 well to a volume of 17.46 million cubic metres (10^6 m^3). The Board then specified that Dome would be required to justify further primary production based on results of the testing program.

4 RECONVENING OF THE INQUIRY AND HEARING

The inquiry and hearing was reopened on 27 November 1984 in Calgary, Alberta. Each of the original participants filed addenda to their initial submissions, incorporating the additional reservoir information provided by the testing program. Table 3 lists the participants.

Interim Decision D 84-30, issued on 13 December 1984, agreed with the concept of cycling, set a dew point pressure for the reservoir fluid in the communicating area, and set out Board views regarding primary production. These matters are discussed in more detail in this final report.

5 ISSUES

As a result of the testing program, many of the questions or uncertainties regarding reservoir and reservoir fluid characteristics have been resolved. The areas of disagreement among the operators now pertain more specifically to details of proposed depletion strategies. Having considered the evidence presented, the Board believes that the issues raised by the inquiry and hearing can be represented as follows:

5.1 General Matters

- regional geology
- areas of communication
- hydrocarbon reserves and mode of communication
- reservoir fluid properties
- need for cycling

5.2 Depletion Strategies

- production/injection configuration
- voidage replacement
- primary production and operating pressure
- cycling rates and facilities
- unitization

6 GENERAL MATTERS

6.1 Regional Geology

All operators were in general agreement that the bank deposit is made up of a series of coalescing bioherms. Gas/water contacts have been defined in the wells located at Lsd 9-7-48-12 W5M (9-7 well), Lsd 5-33-47-12 W5M (5-33 well), and the 7-10 well. The operators agreed that any aquifer associated with the reserves is expected to be of limited extent and not active in terms of pressure support. Regarding the anomalous gas/water contact in the 7-10 well which is interpreted at some 50 metres higher than the 9-7 and 5-33 wells, the operators agreed that the 7-10 well represents a "perched" water situation.

Although all operators agreed that seismic interpretation can be used to locate the shale basin/bank edge boundary, some disagreement on the location of this edge was evident. Petro-Canada and Amoco both agree reasonably well on their interpretations, however, Dome included an additional area in sections 10, 11, and 14 of township 48, range 12, west of the 5th meridian.

Differences also existed in interpretations of the southwest limit of the porous bank deposit. Both Amoco and Dome considered the 5-33 well to have a thin gas zone underlain by a relatively thick water column. Petro-Canada believed this well to be completely wet. This disagreement was based on different interpretation of petrophysical and drill-stem test data. The 5-33 well has been abandoned in the Nisku zone.

Further differences exist in the area of sections 3, 4, 5, and 8 of 48-12 W5M. Amoco considered the entire area to be tight with no gas reserves. Petro-Canada considered the area to be porous and permeable but water-bearing. Dome considered the area to be porous and permeable and gas-bearing. Each operator incorporated its interpretations into its reservoir models.

Given the lack of well control in the area, the Board considers all of these interpretations to be geologically possible. The most conclusive way to determine the rock types and fluids present in this area is through further drilling.

6.2 Areas of Communication

All operators were in agreement that seven of the eleven productive wells in the Carbonate Bank are in some form of pressure communication, these being the 7-34, 10-2, 9-7, 7-10, 13-12, and 3-20 wells, and the well located at Lsd 02/2-19-48-12 W5M (2-19 well). Communication between these wells was initially indicated by the 1982 blowout of the 13-12 well and further confirmed by the recent testing program. For the purpose of this report, the area of communication defined by these wells will be referred to as the main pool area of the Carbonate Bank.

The remaining four wells have not exhibited any pressure communication with the main pool area. The 10-25 and 6-29 wells are considered by all operators to be in a gas accumulation separate from the main pool as no pressure depletion was indicated as a result of the 13-12 blowout or the testing program. Further testing of these two wells will be required to establish the degree of communication, if any, with the main pool area.

The 2-11 and 2-12 wells have not been examined in any detail as yet. All operators have excluded these wells from the main pool area. Petro-Canada considered the two wells to be single-well pools based on fluid data and seismic interpretation. Neither Amoco nor Dome addressed these wells specifically.

The Board agrees with the operators that the seven wells comprising the main pool appear to be in effective pressure communication, and that the remaining four productive wells are not in communication with the main pool area. Pressure and flow testing of the 10-25 and 6-29 wells would aid in interpretations of communication between the two wells. The Board also considers further testing necessary in the 2-11 and 2-12 wells to aid in defining reserves and interwell communication.

6.3 Hydrocarbon Reserves and Mode of Communication

Amoco interpreted the main pool to be a single continuous accumulation with all seven wells in hydrocarbon communication. Amoco has simulated reservoir pressure responses using a 2-dimensional compositional model and estimates the reserves of the main pool to be 2700 x 10^6 m^3. This estimate was based on a blowout rate of 1.41 million cubic metres per day (10^6 m^3/d) (50 MMcf/d) from the 13-12 well. Amoco stated that, depending on geological interpretation and interpretation of the 13-12 blowout rate, reserves could range as high as 5800 x 10^6 m^3. Amoco agreed that infill drilling may be required to resolve uncertainties in gas reserves.

Dome considered the main pool area to be a long continuous bioherm with all seven wells being in hydrocarbon communication. Dome employed a 3-dimensional compositional model to match pressure responses to blowout and test production volumes from the area. Results of the modelling gave an estimate of gas in place for the main pool of 5823 x 10^6 m^3. Dome contended that determination of the reserves is very sensitive to the estimated blowout volume from the 13-12 well. Dome considered the blowout rate to have been as high as 3.52 x 10^6 m^3/d (125 MMcf/d) and that use of a lower blowout rate as proposed by Amoco would result in a lower estimate of gas in place. Dome considers the lands in sections 3, 4, 5, and 8 of 48-12 W5M to be porous and potentially productive and intends to drill a well located at Lsd 11-4-48-12 W5M (11-4 well). Dome stated that further drilling is required to prove reserves in this area.

Petro-Canada interpreted the main pool area to be represented by three separate gas accumulations all in pressure communication through an aquifer. The three accumulations are defined by the 9-7, 2-19, and 3-20 wells (3-20 area); the 10-2, 7-10, and 13-12 wells (7-10 area); and the 7-34 well. Petro-Canada considered communication to be good within an area, but somewhat less between areas. Petro-Canada employed a 3-dimensional fully compositional model to simulate the pressure history of the Carbonate Bank. The model yielded reserve estimates of 1099, 1465, and 873 x 10^6 m^3 for the 7-10, 3-20, and 7-34 areas, respectively, resulting in a main pool reserve of 3437 x 10^6 m^3. These estimates refer to reserves prior to the 13-12 blowout and assume a varying blowout rate averaging 2.11 x 10^6 m^3/d (75 MMcf/d). Petro-Canada suggested that further testing of the 7-10 well would help to improve the estimates of reserves in the area, but admitted that further drilling would be required to improve reserves estimates. Figure 2 displays the operators' interpretations of the gas accumulations in the main pool area.

The Board notes that the determination of reserves is very sensitive to estimates of the blowout rate from the 13-12 well and considers the Amoco estimate of 1.41 x 10^6 m^3/d (50 MMcf/d) to be somewhat conservative. This indicates an upside potential for the Amoco estimate of 2800 x 10^6 m^3. However, the Board agrees with all operators that further drilling will be required to improve reserve estimates in the main pool area. The Board considers the location proposed by Dome to be appropriate for reserve estimates as well as beneficial in determining the mode of communication between the wells.

6.4 Reservoir Fluid Properties

Prior to the testing program, dew point pressure estimates in the main pool area ranged from 27 255 kPa in the 7-34 well to 31 717 kPa in the 2-19 well. Amoco considered the results of the testing program and estimated dew point pressures of 27 028 kPa, 26 994 kPa, and 28 263 kPa as sampled from the 7-34, 13-12, and 3-20 wells, respectively. It suggested that the reservoir fluid dew point was in the range of 26 900 kPa to 28 300 kPa, but concluded that a dew point pressure of 27 220 kPa would be representative of the main pool area. Amoco added that samples obtained from the 10-2 well which yielded dew point pressures ranging from 26 614 kPa to 27 131 kPa were believed to be contaminated and it was therefore skeptical of the results.

Petro-Canada considered three different samples obtained from the 3-20 well which provided dew point pressures of 27 593 kPa, 28 268 kPa, and 27 751 kPa, and concluded that the reservoir fluid in the 3-20 area could be represented by a dew point pressure of 28 000 kPa. Although these samples were obtained at flowing bottom-hole pressures below the dew point, Petro-Canada considered the 28 000 kPa dew point to be a reasonable estimate.

Dome considers the fluid samples from the 7-34 well to be representative of the fluid in the main pool area. Based on the analysis of the July 1983 sample from the 7-34 well, Dome believed the reservoir fluid to be a gas condensate with a dew point pressure of 27 255 kPa and a maximum retrograde liquid accumulation of 27.23 per cent of the hydrocarbon pore volume. Dome added that the 13-12 well fluid exhibited retrograde behaviour similar to the 7-34 well samples.

The Board recognizes the consistency of the fluid samples from the 7-34 well and the similarities between the fluid behaviour in the 13-12 and 7-34 wells. The Board also notes that some uncertainty exists in the samples from the 3-20 well as a result of the bottom-hole flowing pressure dropping below the estimated dew point pressure during sampling. As indicated in Interim Decision D 84-30, the Board believes a pressure of 27 300 kPa is a reasonable estimate of the dew point for the main pool area.

The Board notes that fluid samples from the 6-29 and 10-25 wells with dew point pressures of 27 476 kPa and 27 144 kPa, respectively, are in general agreement with the dew point pressure applied to the main pool area. However, samples obtained from the 2-11 and 2-12 wells yielded dew point pressures of approximately 33 327 kPa and 31 992 kPa, respectively, and retrograde characteristics significantly different than the main pool area and each other. The Board would require that dew point and fluid characteristics of the 2-11 and 2-12 wells be confirmed prior to extended production from these wells.

6.5 Need for Cycling

Based on the area's reserves, the extent of communication, and the fluid properties, all operators were in agreement that cycling is required to optimize hydrocarbon recovery from the main pool.

The Board concurs with the operators that there is potential for enhanced recovery of hydrocarbon liquids from the main pool area and that gas cycling is desirable from a conservation standpoint. The Board notes, however, that there still are varying concepts as to how and when cycling would be developed.

Based on present fluid property data, the Board notes that potential exists for cycling in the 10-25 and 6-29 area, and in the 2-11 and 2-12 area. The Board further recognizes that any decision on cycling in these areas will be dependent on further information regarding reserves and reservoir characteristics yet to be obtained.

7 DEPLETION STRATEGIES

7.1 Production/Injection Configuration

As a result of the testing program, Amoco revised its cycling application to include all seven wells in pressure communication representing the main pool area. Amoco suggested that cycling could be initiated in the 7-10 area with either the 7-10 or 10-2 well used for injection. Although the 7-10 well appeared to be a slightly better location, Amoco stated that the final decision has to be made based upon further simulation studies and should be determined by 1 February 1985. Amoco proposes to implement cycling in the 3-20 area at a later date when processing and injection capacity becomes available. Injection in the 3-20 area would be through the 9-7 well.

Petro-Canada recommended that a cycling scheme in the 7-well main pool area be implemented as soon as possible and is in general agreement with Amoco's proposal. Petro-Canada suggested that the 9-7 well would be used for injection in the 3-20 area, with either the 7-10 or 10-2 well being used for injection in the 7-10 area. It preferred the 7-10 well as it is underlain by water and could experience coning problems as a producer, but suggested that testing of the 7-10 well could aid in the determination.

Although Petro-Canada interpreted the 7-34 well as a separate gas accumulation in communication with the main pool through an aquifer, it proposed to include the well in the cycling scheme. It noted Dome's intention of drilling the 11-4 well which would help to establish the extent of reserves and geological interpretations. Petro-Canada preferred to leave the decision on the production strategy of the 7-34 well until the 11-4 well is drilled. Petro-Canada stated that it will be produced at one time or another, but could possibly remain shut-in until cycling of the 7-10 and 3-20 areas have been completed.

Dome considered a number of depletion scenarios for the main pool area and concluded that a 7-well cycling scheme is required for condensate conservation. Dome suggested that the 9-7 and 7-10 wells would be most suitable for injection purposes, with the possibility of the proposed 11-4 well also being used for injection at a later date. Dome suggested that the entire main pool area could commence cycling simultaneously, or the 7-10 area could be cycled initially with the 3-20 area being brought on at a later date. Dome stated it would support Amoco's application for cycling if the 7-10 well was determined as the most appropriate injector in that area and if agreement was reached regarding voidage replacement and operating pressure. However, Dome did not support the Amoco application in its present form.

Texaco supported the application by Amoco and considered the scheme to be necessary for economic and orderly development of the area's reserves. Texaco noted that the Amoco proposal is the only scheme applied for and should therefore be approved. It added that objections to the cycling scheme centre around operational details such as operating pressure and stated that these matters could be resolved in the Board's approval.

Interim Decision D 84-30 approved the principle set out in Amoco's Application 840147 that a cycling scheme be initiated in the main pool area with the start-up of the Brazeau River plant. The Board notes that some uncertainty exists regarding the location of the injection well in the 7-10 area and is confident that this can be determined by the operators based on reservoir simulation and operational considerations. The Board agrees with all parties that the 9-7 well is a suitable injector for serving the 3-20 area.

7.2 Voidage Replacement Ratio

Amoco proposed a scheme of partial voidage replacement cycling from the inception of production of the main pool area. It contended that partial cycling with variable voidage replacement ratios between 0.6 and 1.0 would allow

for early start-up of the scheme utilizing available plant capacity and would eliminate the need for make-up gas requirements, thereby making the scheme self-sufficient. Amoco added that partial cycling would provide further material balance data. Although Amoco revised its interpretation of the reservoir fluid data to reflect a richer and more retrograde fluid, it contended that, as in the initial application, there is no significant advantage to cycling at full voidage replacement. Amoco estimated that a loss of approximately 4 per cent of the initial condensate could be expected under a voidage replacement ratio of 0.5 as compared to full voidage replacement cycling, however, it considered recovery from an economic standpoint to be optimized by partial voidage replacement. It added that manipulation of the production and injection strategy would optimize the cycling sweep efficiency and minimize losses anticipated under the partial cycling scenario.

Based on the submissions of the other operators and given future performance data, Amoco recognized that full voidage replacement is a possibility. Amoco therefore proposed that partial voidage replacement cycling be initiated from the inception of main pool production with a mandatory review of the optimum voidage replacement ratio after 1 year of operation or before the reservoir pressure falls below 28 600 kPa.

Petro-Canada disagreed with Amoco on matters pertaining to voidage replacement and operating pressure. Regarding the former, Petro-Canada proposed that cycling be conducted at full voidage replacement to maximize condensate recovery from the pool. It had performed technical and economic analyses to indicate that the project economics are insensitive to voidage replacement at ratios of 0.5 to 1.0, but concluded that recovery is sensitive to these ratios. Petro-Canada estimated that a loss of approximately 11 per cent of the initial condensate could be expected under a voidage replacement ratio of 0.7 as compared to full cycling. Petro-Canada admitted that full voidage replacement would not offer any material balance data as available from the partial voidage replacement proposal by Amoco, but added that some testing of the wells under a full voidage replacement scenario would result in improved reservoir data being obtained.

Dome conducted reservoir simulations to observe the effect of voidage replacement on recovery and concluded that condensate recovery is maximized by full voidage replacement as compared to ratios of 0.5 and 0.7. It estimated losses of up to 13 per cent of the initial condensate under a voidage replacement ratio of 0.7 as compared to cycling with full replacement of voidage. Dome had not examined the economics of the scenarios studied and had therefore not as yet selected an optimum scheme.

The Board believes that, from a strict conservation sense, recovery of liquids from the main pool area is sensitive to the voidage replacement ratio. Given the technical analyses of the operators and the uncertainty in the area's reserves, the Board believes that condensate losses incurred by operating at a voidage replacement ratio of 0.7 as compared to full cycling could be as high as 500 thousand cubic metres (10^3 m^3). The Board recognizes that economics must be considered with recovery to determine the optimum overall depletion scheme. However, the Board notes that full voidage replacement cycling schemes have been implemented in the Brazeau River Nisku F, J, K, and M pools which contain reservoir fluids similar in retrograde nature to the fluid in the Carbonate Bank. Also, Petro-Canada has presented an economic analysis concluding that the economics are insensitive to voidage replacement at ratios between 0.5 and 1.0. The Board further considers a scheme of full cycling to be most desirable in the present situation of uncertain reserves and possible flexibility in production/injection strategy due to future drilling. Therefore, for the present and until all partners to the cycling scheme have reviewed the technical and economic considerations in detail, the Board considers a scheme of full voidage replacement cycling to be the optimum for recovery of liquid hydrocarbons from the main pool area.

7.3 Primary Depletion and Operating Pressure

Amoco opposed primary production of the main pool on the basis that it would not provide the substantial pressure margin above the dew point required to cycle at reduced voidage replacement ratios. Amoco added that primary production would not allow for the optimum use of residue gas and would reduce the overall operational flexibility of its proposal. However, Amoco stated that if primary production was to be allowed, this production should be limited such that the average reservoir pressure does not fall below 28 600 kPa. Amoco suggested that monitoring requirements for primary production should allow for 60 days of production followed by a 30-day shut-in period. It added that compensating production from other wells should be provided for to protect equity and that this production should be through a common processing facility if necessary. Amoco further added that unrestricted primary production to the dew point may cause it to reconsider its intention of cycling.

Amoco believed that although no differences in condensate conservation would be realized between partial voidage replacement or primary depletion above the operating pressure, there is a significant economic difference. It added that partial voidage replacement cycling to a specified operating pressure would provide reservoir information similar to that obtained by primary depletion to that pressure.

Under the full voidage replacement scenario, Petro-Canada proposed a minimum operating pressure of 29 800 kPa based on quarterly pressure measurements with 2-week pressure build-ups. It contended that the 3-20 well had shown the highest dew point, estimated as 28 000 kPa. As the wells of the main pool area are in pressure communication, Petro-Canada believed that the highest dew point pressure of the area should be applied in consideration of the operating pressure. Based on model studies, Petro-Canada believed that a minimum pressure margin of 1800 kPa above the highest dew point should be maintained in order to ensure that all areas of the reservoir are maintained above the dew point during cycling. It suggested that an operating pressure of 29 800 kPa may even be somewhat conservative as the model studies considered cycling rates of 423 x 10^3 m^3/d which will likely be increased in the future, thereby causing larger pressure drops and thus requiring a larger pressure margin. Petro-Canada noted that similar full voidage replacement cycling schemes in the Brazeau River area have been approved with pressure margins ranging from 750 kPa to 5800 kPa above the dew point.

Petro-Canada estimated that the proposed testing of the 7-10 and 7-34 wells would decrease the reservoir pressure to near the operating pressure of 29 800 kPa. Petro-Canada therefore opposed any extended primary depletion of the main pool area prior to initiation of cycling. It requested that production prior to cycling be limited to 17 x 10^6 m^3 to allow for the tests. Petro-Canada believed that primary depletion to the dew point followed by full voidage replacement cycling would result in lower condensate recovery than partial cycling to the dew point followed by full cycling. Petro-Canada added that if significant primary production were to occur from the main pool area with no conservation losses, it would attempt to obtain further restrictions on production through rateable take, common purchaser, or common processor proceedings to protect equity and achieve compensating production. Petro-Canada believed that primary production may eliminate the economic incentive of cycling, and lead it to reconsider its intentions.

Dome conducted model studies to compare the effect on recovery of depletion above the dew point. Dome concluded that the same condensate recovery could be expected by partial cycling to the dew point followed by full cycling as would be the case with primary depletion to the dew point followed by full cycling. It therefore proposed primary depletion of its 7-34 well to a minimum operating pressure of 27 500 kPa based on a 2-week build-up period. Dome suggested that this pressure would pertain to a drilling spacing unit, resulting in a somewhat higher average reservoir pressure. Dome noted that Petro-Canada's suggested average reservoir pressure was based on the same philosophy but a lower dew point pressure. It added that the proposed pressure margin of some 250 kPa would be adequate as no increase in the fluid dew point is anticipated and no facilities have to be designed based on the operating pressure. Dome stated that its proposed operating pressure was consistent with the previous dew point restraints.

Texaco submitted that no primary production should be allowed from the main pool area except for testing purposes until a cycling scheme is implemented and unitization has occurred. Texaco believed that further primary depletion from the 7-34 well would give Dome little incentive to unitize and would strengthen Dome's bargaining position.

As discussed in the interim decision, the Board believes that some primary production can be allowed from the main pool area without adversely affecting conservation. Primary production would not be allowed from a well whose extrapolated built-up pressure is less than 28 800 kPa with pressures determined every 3 months from any well on primary production. The determination of the pressure must incorporate the results of a build-up test not less than 2 weeks in duration. The Board considers the representative dew point for the main pool area to be 27 300 kPa and considers a pressure margin of some 1500 kPa appropriate to provide a suitable operating margin for a full voidage replacement cycling scheme. The Board further believes primary depletion to 28 800 kPa will expedite further reservoir information beneficial in determining the extent of reserves. The Board notes the intentions of Amoco and Petro-Canada to obtain compensating and competitive production from their wells in situations where primary depletion is occurring from the 7-34 well.

The Board notes that Dome and Amoco agree that injection of dry gas will not increase the dew point of the reservoir fluid to any significant extent, and therefore believes that conservation need not be affected at pressures above the initial dew point.

7.4 Cycling Rates and Facilities

Amoco proposed a scheme of variable voidage replacement cycling with production rates between 300 and 420 x 10^3 m^3/d. It stated that 280 x 10^3 m^3/d processing capacity would be available at the West Pembina plant for production from the 7-34 well, and that 170 x 10^3 m^3/d processing capacity has been allocated to wells in the main pool area at the Brazeau River plant. Amoco stated that injection requirements could be met by the Brazeau River plant which has a nominal capacity to provide gas for injection of some 300 to 420 x 10^3 m^3/d depending on equipment scheduling and the requirements of other pools. Amoco noted that the Brazeau River Nisku

F Pool (F Pool) is scheduled to commence injection in July 1985 but added that 225 to 395 x 10^3 m^3/d injection capacity would still be available for the main pool area.

Amoco believed that cycling could be initiated in the 7-10 area commensurate with the start-up of the Brazeau River plant on 1 April 1985. The 3-20 area could commence production in December 1985 as injection capacity becomes available. Although the details of processing were yet to be finalized, Amoco suggested that a number of possibilities exist including the splitting of production between the Brazeau River and West Pembina facilities.

Amoco stated that the 1 April 1985 commencement date required early approval of cycling to allow for the purchase of pipeline materials and winter pipeline construction. Amoco further stated that if the winter construction window is not met, it would prefer to see the pool shut-in for 1 year until the appropriate facilities are in place. Amoco noted that some uncertainty exists with respect to reserves and the potential for further drilling but believed that cycling should not be delayed to reflect these uncertainties.

Petro-Canada considered the total project optimum rate to be between 846 and 1269 x 10^3 m^3/d based on preliminary economic evaluations. Based on estimates of current available capacity, Petro-Canada suggested an initial rate of 423 x 10^3 m^3/d, comprised of 240 x 10^3 m^3/d from the 7-10 area and the remainder from the 3-20 area. It suggested that cycling could commence with production to the West Pembina plant in April 1985. Injection would be from both the West Pembina and Brazeau River plants with additional Carbonate Bank gas being produced to the Brazeau River plant in June 1985. High pressure injection lines from the Brazeau River plant to the two injection wells are scheduled for construction this winter, with high pressure gas from the West Pembina plant obtainable through existing lines connected at the F Pool.

Petro-Canada recognized that the uncertainties in reserves and drilling potential could result in different production/injection strategies being developed in the future. However, it stated that this situation is common and that any changes to the proposed strategy would not be significant. Petro-Canada therefore believed that the uncertainties should not delay implementation of cycling.

Dome did not propose a definite scheme but considered cycling rates of 423 x 10^3 m^3/d in its model studies, consisting of 254 x 10^3 m^3/d from the 7-10 area and the balance from the 3-20 area. Dome assumed cycling rates to double in 1988 due to increased plant capacity from declining reserves and plant expansions.

Dome stated that 281.7 x 10^3 m^3/d (10 MMcf/d) of processing capacity at the West Pembina plant had been allocated to its share of production from the Carbonate Bank through the 7-34 well. Upon unitization of the main pool area, this capacity would be made available to the unit for the cycling scheme. Dome's understanding was that there would be an additional 169.0 x 10^3 m^3/d (6 MMcf/d) of processing capacity allocated to the main pool area at the Brazeau River plant. Injection options exist at the West Pembina plant through a direct supply or through a 169.0 x 10^3 m^3/d exchange with owners of the F Pool such that the main pool would receive gas from the Brazeau River plant and the F Pool's injection gas would be supplied by the West Pembina plant. Dome added that there is potential for doubling the processing capacity of the West Pembina plant in the future which could alter the use of facilities. Dome stated that the parties are working toward having the facilities in place and an agreement to initiate cycling about 1 April 1985.

The Board notes that capacity should be available for an initial cycling rate of 423 x 10^3 m^3/d. It recognizes that some differences exist between the operators regarding the allocation of production between the 7-10 and 3-20 areas and believes that these differences should be resolved prior to the commencement of cycling. The Board also notes that Petro-Canada proposed an optimum rate higher than the initial rate, and recognizes that increases in cycling rates may be desirable in the future.

The Board recognizes that the utilization of facilities for cycling and the corresponding cycling rates have not yet been decided. It notes that considerable flexibility exists given the connections of the Brazeau River plant and the West Pembina plant through the F Pool and through the approved pipeline between the 7-10 and 7-34 wells. The Board believes that some combination of the two processing plants and gathering systems would provide an acceptable mode of operation and is confident that arrangements can be made regarding processing facilities such that cycling could commence with the start-up of the Brazeau River plant. In its interim decision the Board approved the principle of cycling to enable the purchase of pipeline materials and possible winter construction.

7.5 Unitization

Amoco stated that common ownership of the area would be required prior to commencement of cycling, and is confident that unitization could be achieved by the projected start-up date of 1 April 1985. Although Amoco admitted that unitization would likely be a condition to cycling implementation, it suggested that a condition of a cycling approval could be an agreement between the parties rather than a completed unitization agreement.

Petro-Canada believed that production of the main pool in excess of the proposed test rates should not be permitted prior to unitization and implementation of the cycling scheme.

Dome believed that competitive primary production could take place until such time as a unit has been formed and unitized operations commenced. Dome stated that the royalty-free status of the 7-34 well provided an economic incentive to pursue competitive primary production, and encouraged the other operators to commence primary production. Dome states that although allowing primary production would result in less incentive for Dome to unitize than Petro-Canada or Amoco, it would be prepared to unitize if sufficient recognition was given to the value of 7-34 production.

Texaco submitted that there should be no production except for test purposes from the main pool area until a cycling scheme is in place and unitization has occurred. Texaco favoured a cycling scheme approval being conditional on unitization of the project lands.

The Board recognizes that all parties are involved in unitization discussions with the intent of initiating cycling by 1 April 1985. The Board further recognizes that significant differences exist in the areas for which unitization is being sought, based on geological interpretations. The Board believes that unitization is required for cycling to proceed in an efficient manner, but that competitive primary production to the specified operating pressure can occur. The Board therefore expects a unit agreement or equivalent operating agreement to be completed prior to the commencement of cycling, and is of the view that continuance of primary production should not impede the early commencement of cycling.

TABLE 1 CARBONATE BANK WELLS

Well Location	Working Interest Owners
02/6-29-47-11 W5M (6-29)	Shell HBOG*
10-25-47-12 W5M (10-25)	Petro-Canada* Amoco
5-33-47-12 W5M (5-33)**	Ranger Oil Limited (Ranger) Dome*
7-34-47-12 W5M (7-34)	Dome*
10-2-48-12 W5M (10-2)	Amoco* Dome
9-7-48-12 W5M (9-7)	Texaco*
7-10-48-12 W5M (7-10)	Amoco* Petro-Canada
13-12-48-12 W5M (13-12)	Amoco* Petro-Canada
02/2-19-48-12 W5M (2-19)	Petro-Canada* Amoco Texaco
3-20-48-12 W5M (3-20)	Petro-Canada* Amoco
2-11-48-13 W5M (2-11)	Petro-Canada* Amoco Texaco
2-12-48-13 W5M (2-12)	Petro-Canada* Amoco Texaco

* Well operator
** Abandoned in the Nisku zone.

TABLE 2 BOARD DECISIONS RELEVANT TO CARBONATE BANK DEVELOPMENT

Decision	Date	Purpose
D 81-36	23 December 1981	Approval of HBOG West Pembina gas processing plant.
D 83-11	14 July 1983	Approval of HBOG gathering system enabling production of Carbonate Bank and pinnacle wells to West Pembina plant. Decision also imposed dew point restraint on production from the 7-34 well.
D 83-20	19 August 1983	Approval of Petro-Canada Brazeau River gas processing plant.
D 83-29	7 December 1983	Approval of Petro-Canada gathering system enabling production of Carbonate Bank and pinnacle wells to Brazeau River plant. Decision also imposed dew point restraints on production from the 7-10 and 3-20 wells.
Memorandum of Decision	18 July 1984	Board supported the joint testing program proposed by Carbonate Bank operators and deferred Amoco's application for a cycling scheme until conclusion of inquiry into optimum depletion strategy. Board imposed a restriction on the volume of gas produced from the 7-34 well during the testing program.
D 84-19	18 July 1984	Approval of Amoco pipeline connecting the 7-10 well to the HBOG gathering system at 7-34.
D 84-30	13 December 1984	Approval in principle for a cycling scheme in the Carbonate Bank subject to completion of a unit agreement. Board set a dew point pressure of 27 300 kPa for the communicating area and allowed primary production to a pressure of 28 800 kPa.

TABLE 3 THOSE WHO APPEARED AT THE INQUIRY AND HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) A. G. Kruse J. E. Lipton	J. G. McLeod, P.Eng. J. D. Griffith, P.Eng. R. Arnold, P.Eng.
Dome Petroleum Limited (Dome) F. M. Saville, Q.C. R. A. Neufeld	J. R. Moore, P.Eng. Dr. G. Besserer, P.Eng. E. J. Muchowski, P.Eng.
Petro-Canada Inc. (Petro-Canada) B. K. O'Ferrall	G. A. Reitzel, P.Eng. K. M. Tutty, P.Eng. J. Katay, P.Geoph. J. McLaws, P.Geol.
Texaco Canada Resources Ltd. (Texaco) W. F. Muscoby	
Energy Resources Conservation Board staff H. R. Hansford R. J. Cox, P.Eng. H. R. Keushnig, P.Eng. R. Walker, P.Geol. D. B. Fairgrieve, P.Geol.	

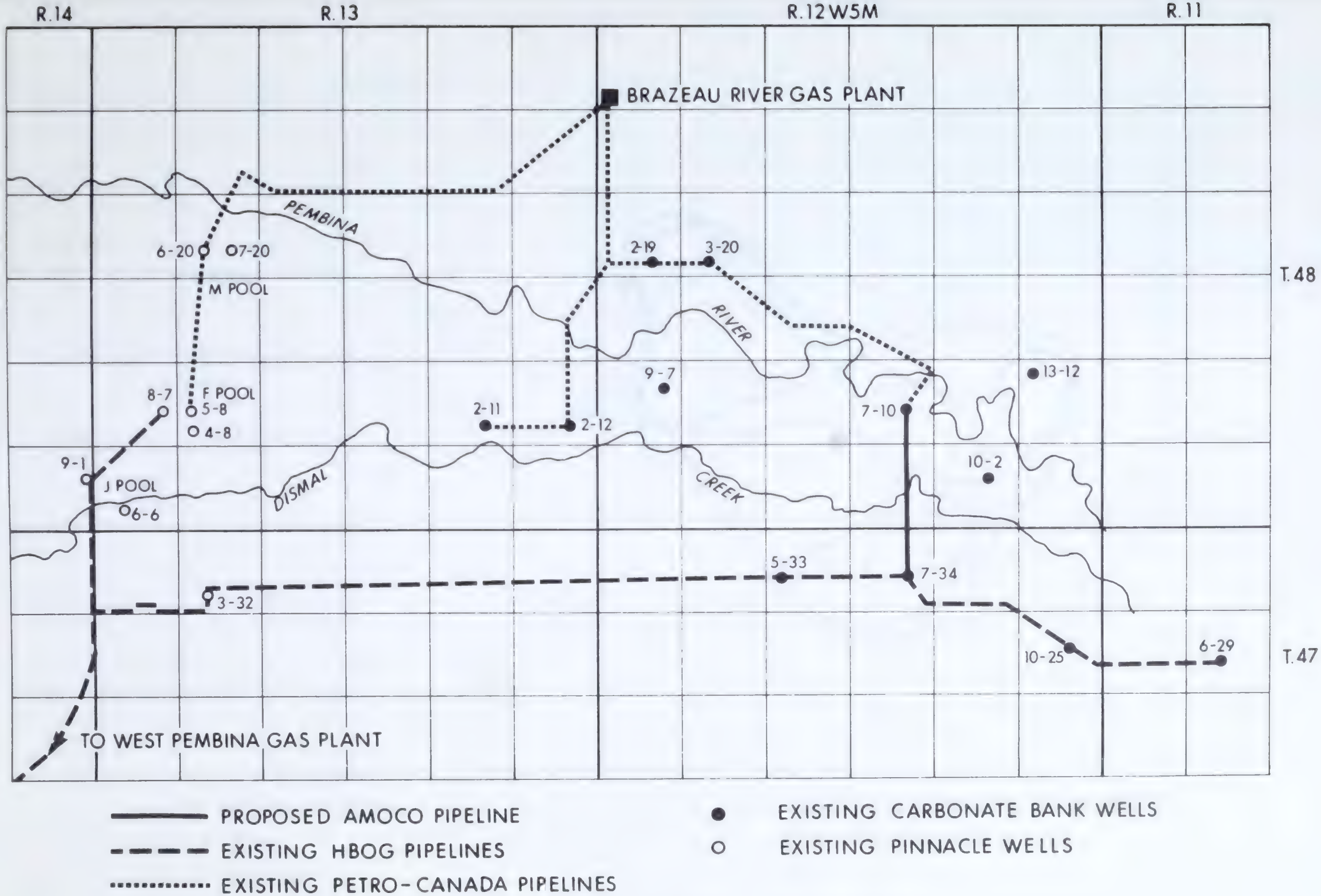
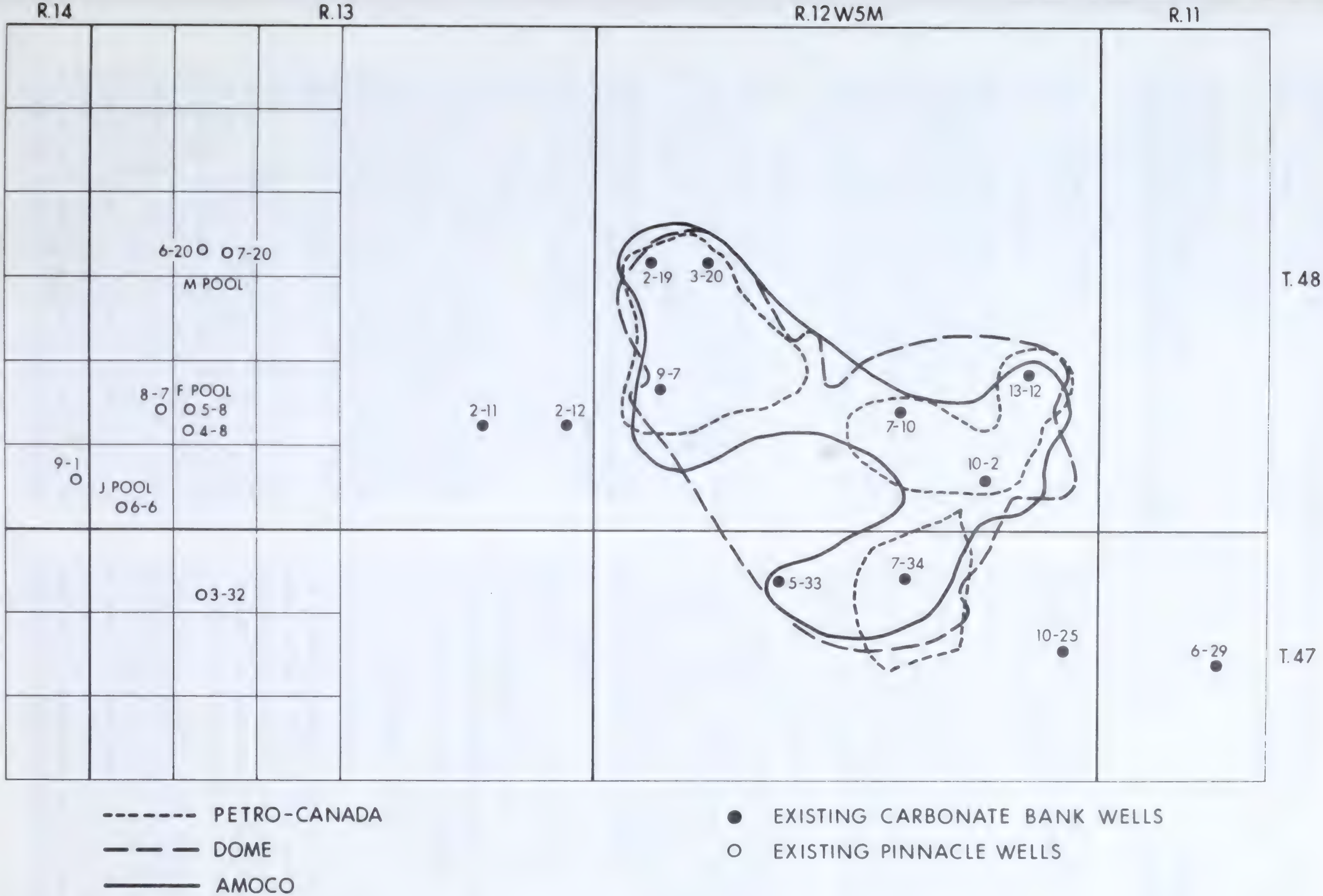


FIGURE 1 GAS PROCESSING AND GATHERING FACILITIES
BRAZEAU RIVER CARBONATE BANK AREA



This figure represents approximate zero pay boundaries for comparative purposes and it is not intended as a precise statement of the operators' interpretations.

FIGURE 2 INTERPRETATIONS OF MAIN POOL AREA
BRAZEAU RIVER CARBONATE BANK AREA

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

SUNCOR INC.
RATEABLE TAKE OF GAS
ROSEVEAR BEAVERHILL LAKE A POOL

Decision D 85-11
Application 840777

1 INTRODUCTION

1.1 The Application

Suncor Inc. applied under section 23 of the Oil and Gas Conservation Act (the Act) for an order to distribute gas production in an equitable manner among the wells in the North Rosevear Area (the North Area), operated by Suncor Inc., and the east leg of the South Rosevear Gas Unit No. 1 (the Unit), operated by Shell Canada Resources Limited, of the Rosevear Beaverhill Lake A Pool (the A Pool).

1.2 The Hearing

The application was considered at a public hearing on 20 and 21 November 1984, in Calgary, Alberta, with V. E. Bohme, P.Eng., J. R. Pow, P.Eng., and H. J. Webber, P.Eng., sitting.

Shell Canada Resources Limited submitted an intervention opposing the application. TransCanada PipeLines Limited intervened for the purposes of cross-examination and presentation of argument.

1.3 Background

The Board currently recognizes the A Pool as a single pool in the Beaverhill Lake Formation underlying 20 sections in townships 53, 54, and 55, ranges 14 and 15, west of the 5th meridian (W5M), as shown by Figure 1. Both Suncor and Shell interpret the A Pool to consist of two separate accumulations which they refer to as the east and west legs of the pool, the east leg being the subject of the application.

The east leg of the A Pool contains eight wells, of which four are currently producing gas, and four are capped and have never produced. The east leg is divided between the Unit and an area referred to by Suncor as the North Area, both of which are shown by Figure 1. The producing wells in the North Area are located in Lsd 10-33-54-15 W5M (the 10-33 well) and Lsd 6-34-54-15 W5M (the 6-34 well). Of the wells contained in the Unit's portion of the east leg, the wells in Lsd 10-12-54-15 W5M (the 10-12 well) and Lsd 11-24-54-15 W5M (the 11-24 well) are producing gas. The well in Lsd 11-13-54-15 W5M (the 11-13 well) is considered to be incapable of production due to poor reservoir characteristics.

The wells in the North Area are operated by Suncor and all sections have common ownership, with Suncor and Shell each having a 50 per cent working interest. The Unit is operated by Shell, which is the major working interest owner with approximately 49.2 per cent. Suncor has a working interest of about 6.8 per cent and the remaining working interest of the Unit is divided among eight other companies.

All of the gas produced from the A Pool is sold to TransCanada under separate gas sales contracts with the owners of the North Area and the Unit. Because the Unit extends over the west leg and part of the east leg, production may be taken from either leg to meet the Unit's contract nominations. This opportunity is not available to the North Area owners as only the east leg's gas reserves are subject to their contract.

2 ISSUES

The Board considers the issues to be

- the delineation of the A Pool,
- the need for a rateable take order, and
- the basis for distributing production.

3 POOL DELINEATION

3.1 Views of Suncor

The applicant submitted that the present Board-designated outline for the A Pool as a single pool is incorrect. It contended that the A Pool consists of an east leg and a west leg, with the two pools being separated by a surge channel facies functioning as a permeability barrier.

Suncor said that there is no direct geological or geophysical evidence of the channel other than the low net pay values observed in the wells on the west flank of the east leg, notably those in Lsd 11-13-54-15 W5M and Lsd 11-26-54-15 W5M. Suncor stated that its seismic data could be used to identify only the presence of thick porous zones, and not the position of the pool limits.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Suncor Inc. (Suncor) K. S. MacFarlane	J. D. Hankinson, P.Eng. L. E. Tupper, P.Eng. R. J. Waraksa, P.Eng. A. J. Wells, P.Eng. W. H. Wolff, P.Eng. W. J. Wakaryk, P.Eng. of Scientific Software-Intercomp
Shell Canada Resources Limited (Shell) K. F. Miller	B. M. Campbell, P.Eng. R. A. Hamm, P.Eng. D. J. Hemphill, P.Eng. W. H. Stewart, P.Eng.
TransCanada PipeLines Limited (TransCanada) E.W.H. Mallabone L. A. Wahl	
Energy Resources Conservation Board staff C.J.C. Page L. E. Campbell, P.Geol. G. M. Pilling, C.E.T. E. E. Smith, P.Eng.	

The applicant indicated that the most diagnostic criterion used to conclude pool separation was the pressure difference observed between the east and west legs. The east leg commenced production in mid 1976 and the west leg followed in 1979. Suncor stated that although there was an observed pressure drop in the west leg between these dates, it is not considered to be significant. Suncor further stated that its reservoir simulation model study also indicated the absence of communication between the two legs because no acceptable pressure match could be achieved if communication were assumed to occur. Based on this knowledge, the applicant concluded that essentially no communication exists between the east and west legs and that the surge channel facies provides a barrier between the two pools.

3.2 Views of Shell

Shell agreed with the applicant's evidence and conclusions with respect to pool delineation, and suggested that the existing pool designation order be amended to reflect the two-pool concept.

3.3 Views of the Board

The Board concludes from the geological evidence that the wellbore data suggests the existence of a tight channel facies between the east and west legs. The Board believes, moreover, that the pressure evidence provides reasonable proof regarding the existence and position of the two separate legs, and it is prepared to amend the existing G order for the A Pool to reflect the outline shown by Figure 2.

4 NEED FOR AN ORDER

4.1 Views of Suncor

Suncor stated that gas from both the North Area and the Unit is currently under contract to TransCanada and both contracts are normal reserve base contracts. Since the east and west legs of this reservoir have been identified as two separate pools, the Unit owners have the opportunity to cross-dedicate reserves between the two legs, whereas such an opportunity is unavailable to the owners of the North Area where the west leg is absent. Because of this cross-dedication prerogative, the Unit may meet its total contract nominations from wells in either the east or west legs and can produce from the east leg at a rate disproportionate to its reserve base. Suncor contended that the Unit, since commencing production in November 1979, has produced gas preferentially from the east leg in an attempt to recapture the reserves lost to the North Area before that date.

Suncor submitted that since early 1981, the Unit has been taking a disproportionately high percentage of the total east leg production in relation to the Unit's share of the east leg's reserves. In 1981 and 1982, the Unit's share of production was approximately 40 per cent of the total production, increasing to over 50 per cent in 1983. Suncor contended that the North Area has about 73 per cent of the remaining gas reserves in the east leg and that at the current production rates, some of the North Area's share of remaining gas is being drained. Suncor contended that at the Unit's current production rate, the North Area could be drained of approximately 380 million cubic metres (10^6 m^3) of gas when the pool is depleted. This would be about 10 per cent of the remaining gas in place recognized by Suncor for the North Area as of 1 November 1983.

Suncor estimated that approximately 170 x 10^6 m^3 of gas had migrated from the Unit to the North Area during the period 1976 to 1979. It stated that the direction of drainage had been reversed and that, at the time of the hearing, the net drainage was probably zero. Suncor claimed, however, that any drainage occurring before the Unit commenced production is irrelevant to the Board's consideration of the application.

Suncor contended that when regard is paid to the purposes of the Act, particularly as set out in section 4(d), and the fact that the withdrawal of gas from the Unit's portion of the east leg is not subject to the same type of restrictions that affect the North Area, the order is justified.

4.2 Views of Shell

Shell stated that before the Unit commenced production, a substantial volume of gas migrated to the North Area. It stated that, because the Unit originally contained about 40 per cent of the reserves, it was entitled to produce 40 per cent of the original recoverable gas in place. To do this, the Unit's production rate has been increased to recover the gas that had migrated north of the Unit boundary and Shell stated that the Unit would thereafter reduce its proportion of the east leg's production to 40 per cent.

Shell submitted that the Board encourages unitization to accomplish improved efficiency and economy in developing and producing a pool. Shell claimed that the Unit working interest owners would suffer an injustice if the net influx of gas to the North Area which occurred during Unit negotiations was not eligible to be drawn back to the Unit. Shell suggested that there was no legislation or Board guideline to prohibit drawing back previously migrated gas and, therefore, maintained that it has the right to draw back the gas that had migrated to the North Area. Shell also suggested that gas migration from the north to the south had probably commenced or would commence soon. It did not accept Suncor's suggestion that the net influx of gas to the North Area is now zero or near zero.

Shell submitted that one expressed purpose of the Act is to give each owner the opportunity of producing or receiving his share of the gas from the pool. However, Suncor's suggestion to base the share of reserves on current rather than original reserves would not result in equity being preserved among owners in the pool. In summary, Shell stated that a rateable take order is unwarranted where an owner produces no more than its share of the original reserves in place. Therefore, Shell requested that the application be denied.

4.3 Majority Views of the Board

The views expressed below are those of V. E. Bohme and J. R. Pow (the majority).

The Board has indicated in previous rateable take decisions[1] that, before it will grant an application under section 23, it must be convinced that:

- the applicant has been or is being deprived of the opportunity to obtain its equitable share of the pool's production or reserves, and
- gas drainage has occurred subsequent to the completion of a well on the applicant's property.

The majority believes that both matters warrant consideration in the treatment of the subject application.

4.3.1 Deprivation of an Equitable Marketing Opportunity

Decision 77-23 states that a proper basis for assessing whether a well owner is being deprived of an equitable marketing opportunity is to "determine whether or not each owner has and will continue to have a reasonable opportunity to produce gas at rates more or less in proportion to his recoverable reserves". The majority believes that this approach is appropriate for assessing the marketing opportunities associated with the subject application. In employing this approach, the current status of Suncor's marketing opportunity is considered,

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[1] For example, Decision 77-23 dated 23 November 1977 relating to an application by Ridgewood Resources Ltd. for the rateable take of gas from the Big Bend McMurray B Pool, and a decision dated 16 March 1966 relating to an application by Spooner Mines and Oils Limited for a special order affecting production from the Provost Viking A Pool.

as well as Shell's plan to continue production at rates that would be disproportionate to its Board-recognized share of the east leg's reserves.

In section 5.3, the Board concludes that, for distribution purposes, 67 per cent of the east leg's reserves underlie the North Area. However, because of the Unit's production practices which were made feasible by its cross-dedication opportunity, the North Area's share of the east leg's production is, and will likely continue to be, less than 67 per cent. At present its share of the production is about 45 per cent but, according to Shell, that share will eventually be permitted to increase to, and remain at, 60 per cent, a value representing Shell's interpretation of the North Area's share of the east leg's reserves.

As the North Area's production rate is fixed by its contract, the Unit, by capitalizing on its cross-dedication opportunity, can vary its production to take a disproportionately large share of the east leg's production. The North Area thus has no assurance that it has or will have an opportunity to produce gas at rates more or less in proportion to the Board's recognized share of the east leg's reserves. The majority, therefore, concludes that Suncor has been and is being deprived of the opportunity to obtain its share of the east leg's production and reserves.

4.3.2 Drainage

The majority finds from its examination and interpretation of the evidence that gas in the east leg:

- migrated northward from the Unit into the North Area between early 1976, when production from the North Area commenced, and approximately mid 1981, by which time the Unit had been producing for about 1.5 years, and

- has been migrating southward from the North Area into the Unit since approximately mid 1981.

The majority notes that Suncor's estimate of zero net drainage at the time of the hearing was based on its 73/27 split of the initial gas reserves in the east leg. However, on the basis of a 67/33 split of the original reserves in the east leg, as adopted by the Board, and a cumulative production split of about 75/25, the majority concludes that at this juncture some of the gas originally under the Unit's lands has not returned to the Unit but still resides in the southern lands of the North Area. Further, at the current proportions of production from the east leg, it would take several years for all of this migrated gas to return to the Unit.

Given these circumstances, the Board is required to decide whether or not drainage has occurred, and it must take into account Shell's argument that drainage has not and cannot occur as long as a part of the Unit's original reserves resides in the North Area.

In assessing Shell's position, the majority believes it appropriate to take into account certain principles enunciated in previous decisions. These principles are, firstly, that gas migrating from a portion of a pool where no production was occurring is not improper and, secondly, that drainage occurring during a normal negotiation period is reasonable given competitive operations. The majority acknowledges, nonetheless, that earlier decisions dealt with straightforward situations where the applicants had experienced outgoing drainage only. Even in these cases, however, the migrated gas was not recognized in the Board's rateable take order, and production rates were not adjusted to permit the return of the migrated gas.

In deliberating on the drainage aspect of the subject application, the majority has focused on two principles:

- drainage up to the date of a rateable take order is not improper, and

- the applicant must prove that gas drainage has occurred subsequent to the completion of a well on the applicant's property.

In applying these principles to the subject application, the majority believes it is justified in dismissing, as irrelevant, the fact that past production has caused a certain volume of gas to migrate from the Unit into the North Area where some of the migrated gas still remains. In a competitive environment, the law of capture applies and the migrated gas belongs only to the producer who reduces it to his possession. With no rateable take or common purchaser order in effect, no regulatory provision existed to override the law of capture.

Concerning the second principle, the majority, as previously mentioned, is satisfied that the migration of gas from the North Area to the Unit has occurred since approximately mid 1981, and is still occurring.

In conclusion, the majority finds that the Unit has been and is draining gas from the North Area.

4.3.3 Conclusion Regarding the Need for a Rateable Take Order

Having regard to the marketing and drainage aspects of the subject application, the majority concludes that a need exists for a rateable take order to equitably distribute the rate of the east leg's production between the North Area and the Unit.

4.4 Minority Views of H. J. Webber

In considering the matter of the need for a rateable take order, I agree with the majority view respecting the distribution of gas within the east leg of the A Pool and the movement of gas within the east leg over time. However, I do not find that the applicant is being deprived of the opportunity to obtain his share of the gas in the east leg, or that inequitable drainage is occurring. In my opinion the majority members of the panel appear to have placed undue reliance on previous decisions of the Board, all related to unidirectional drainage, without giving sufficient weight to the unique circumstance, in the subject case, of two-way drainage over time. This reliance has a direct bearing on the interpretations related to each well owner's share and whether any drainage which may be occurring is inequitable.

I believe that section 23 of the Act makes it clear that a rateable take order should not be issued until it has been demonstrated that an owner, under normal competitive operations, will not have the opportunity of producing his share of gas in a pool in question. It is important, then, to determine what constitutes that owner's share of the gas.

In my opinion, an owner's rightful share of the gas in a pool should, as a maximum, include both the producible gas which lay under his lands before any production commenced from the pool, and any gas which was captured from adjoining lands. It is my view that to be captured, the gas must be physically produced through a well or wells. I further believe that gas which has migrated from one owner's lands to another's is rightfully producible by either owner and thus cannot be considered under section 23 of the Act to be part of the rightful share of the owner onto whose lands the gas has migrated. This is at least implied by the Board in previous rateable take decisions, because the method of distributing production, where an order was necessary, paid no heed to migratory gas.

In the case at hand, gas originally on Unit lands has migrated onto North Area lands, and some of it remains there. The applicant has not claimed to have produced any of this Unit gas, and my determination of the movement of gas indicates that Unit gas likely moved only a relatively short distance towards the nearest North Area producing well before reversing its direction. I thus conclude that none of the migratory gas was captured and that the gas which the North Area well owners can rightfully consider as their share is the producible gas originally on their lands. This leads me to the conclusion that inequitable drainage has not yet taken place and an order need not be issued until it has. Examination of the evidence convinces me that the implementation of the majority decision would likely result in essentially all of the gas which has migrated northward and remains on North Area lands being available for production by North Area wells and not by wells in the Unit.

The fact that the North Area well owners do not currently have the opportunity to produce at the higher ratio of production to initial reserves of the Unit wells does not, in my opinion, constitute a reason for the issuance of an order. I believe it appropriate that the current competitive situation be allowed to continue until such time as the North Area well owners may be able to demonstrate that their rightful share of gas in the North Area cannot be acquired due to the drainage of part of this share onto Unit lands. At that time, if the Unit owners failed to act to reduce the Unit's east leg production appropriately, the North Area well owners could apply for the rateable take of gas in the east leg. Such an order, applied at that time, could logically permit each well owner the opportunity of producing his share of the gas in the east leg.

In conclusion, I find that the application should be denied.

5 BASIS FOR DISTRIBUTION

5.1 Views of Suncor

Suncor submitted that the future production from the east leg should be apportioned 73 per cent to the North Area and 27 per cent to the Unit on the basis of the results of the reservoir simulation model study prepared for it by Scientific Software-Intercomp. The study indicated that the original raw gas in place in the east leg was 7418×10^6 m^3. At 1 November 1983, the remaining raw gas in place was estimated to be 5317×10^6 m^3, with 72.7 per cent of the volume allocated to the North Area and 27.3 per cent to the Unit, and Suncor proposed that the remaining raw gas in place be used to determine the split of future production from the east leg. Suncor stated that the results from its model would be accurate to within 5 to 7 per cent in determining both reserves and distribution of reserves. Suncor said that a conventional material balance calculation to determine reserves distribution was not appropriate because certain assumptions are needed to account for influx of gas. On the other hand, a dynamic material balance simulation model, as used, gives a much better result for determining reserves because all well pressures are matched and gas influx is an automatic calculation. Suncor further submitted that a volumetric estimate of gas reserves would not be accurate due to the nature of the pool and the fact that the edge of the pool is not well defined.

Suncor said that although it preferred to use the results from the simulation model for apportioning, if the Board were to use a volumetric analysis, the split using data

from the eligible wells (which it interpreted to be tied in and capable of production) in the east leg would be 72.7 per cent and 27.3 per cent for the North Area and the Unit, respectively. Suncor submitted wellbore parameters based on log analyses for all wells as shown in Table 2 and suggested that a water saturation of 15 per cent could be used where no value was provided in its application.

Suncor submitted that, because the North Area and the Unit each has common ownership, distribution of production among the wells for purposes of the applied-for order would not be necessary.

Suncor volunteered to administer the apportioning of production under a Board order between the North Area and the Unit. It stated that since the order would apply for the duration of the subsisting gas purchase contracts, a review on an annual basis would be warranted. The applicant accepted that both it and Shell could conduct the reviews to ensure compliance with the order.

5.2 Views of Shell

Shell proposed that the ultimate cumulative production from the east leg be distributed 60 per cent to the North Area and 40 per cent to the Unit based on material balance calculations. These calculations indicated an original raw gas in place of 7020 x 10^6 m^3 in the east leg of which 58.5 per cent and 41.5 per cent were underlying the North Area and the Unit, respectively. As of 31 August 1984, the remaining recoverable reserves were estimated to be 4213 x 10^6 m^3 with the same distribution as in the original gas-in-place case. Shell said that after all of the migrated gas has returned to the Unit, it would adjust the production rate from the Unit to effect the proposed distribution.

Shell noted that in using a material balance calculation for the separate areas of the east leg, corrections must be made to account for the effect of migrated gas. Shell made such corrections and explained its methodology. Shell also employed a reservoir simulation model and said it was used to assist in calculating a reasonable reserves match and a pressure history match for the wells, thus confirming the material balance.

Shell submitted that its material balance estimates of the original raw gas in place of the North Area and the Unit could be accepted with confidence because the reservoir has good transmissibility. Also, this technique eliminates the need for volumetric mapping and minimizes the need for subjective interpretations.

In response to questioning at the hearing, Shell filed a petrophysics summary showing net pay, porosity, and water saturation values which were derived from logs and cores. It said that if the Board were to decide to apportion production on the basis of volumetric considerations all capable wells should be recognized and its wellbore values (see Table 2) could be used.

Shell submitted that, in the event the Board found it necessary to issue a rateable take order, the sharing arrangement for production in the North Area and the Unit could be administered on a voluntary basis by annual reporting by both parties. Further, an undertaking could be made to report annually to the Board on any disparities.

5.3 Views of the Board

Having regard for the majority finding expressed in section 4 of this report, the Board accepts that an order distributing the amount of gas that may be produced from the pool among the wells in the pool should be issued. The Board now directs its attention to the basis for the distribution and to the administration of the order.

The Board believes that the amount of gas that may be produced from wells in the east leg of the A Pool should be distributed between the North Area and the Unit in proportion to the initial reserves underlying the drilling spacing units of the capable wells. It believes that the initial reserves should be calculated on the basis of wellbore parameters, assuming equal areas for each capable well. The Board believes it unnecessary to allocate the proportion of gas which may be produced in each of the two areas among the wells in the areas.

The Board has reviewed the wellbore parameters of each capable well, as submitted by Suncor and Shell, and agrees with both that the 11-13 well is incapable of production and, therefore, has not included it in the proportioning calculations.

Having regard for the evidence as summarized in Table 2, the Board believes that an equitable distribution of the total annual production of the east leg of the A Pool would be 67 per cent from the North Area and 33 per cent from the Unit. The Board notes that it has more confidence in Suncor's reservoir simulation study than either Shell's reservoir simulation model or material balance, and recognizes that somewhat more of the initial reserves may have been present in the North Area, but due to the lack of more definitive evidence, the Board has adopted the 67/33 split based on wellbore parameters.

The Board finds it appropriate that all production balancing would be done on an annual calendar-year basis, with proportions of gas to be taken from each area in accordance with the Board's decision, as expressed in the rateable take order, from the effective date of the order.

Proportioning of production would therefore be in effect for only part of 1985. The Board finds that it would be inappropriate to issue annual allowable production rates for the wells because of the desire of the well owners to maximize production within contract constraints, subject to the proportions being maintained. Further, the Board believes that the responsibility of administering the proportioning should rest with the owners, subject to the understanding that these parties may apply to the Board for any change that may appear necessary.

6 DECISION

The Board has decided that:

- the Rosevear Beaverhill Lake A Pool as currently designated by the Board be divided into two pools, as shown by Figure 2,
- an order be issued distributing the amount of gas that may be produced from the east leg of the A Pool between the North Area and the Unit in proportions of 67 and 33 per cent, respectively, and
- the administration of gas production under the order be carried out by Suncor Inc. and Shell Canada Resources Limited.

DATED at Calgary, Alberta, on 25 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

J. R. Pow, P.Eng.
Acting Board Member

H. J. Webber, P.Eng.
Acting Board Member

TABLE 2 WELLBORE PARAMETERS — CAPABLE WELLS IN THE ROSEVEAR BEAVERHILL LAKE A POOL — EAST LEG

	Suncor			Shell		
Well Location W5M	**Net Pay metres**	**Porosity fraction**	**Water Satur. fraction**	**Net Pay metres**	**Porosity fraction**	**Water Satur. fraction**
11-6-54-14	12.2	0.07	0.124	11.5	0.084	0.21
4-7-54-14	7.0	0.032	0.17	7.0	0.059	0.25
10-12-54-15[c]	6.1	0.063	0.15	6.9	0.061	0.19
11-24-54-15[c]	24.4	0.07	0.03	20.1	0.072	0.15
Hydrocarbon Pore Volume Factor[a] (Unit)		2.918			2.644	
11-26-54-15	6.1	0.104	0.15	5.2	0.091	0.29
10-33-54-15[c]	24.4	0.09	0.05	17.7	0.101	0.07
6-34-54-15[c]	39.6	0.095	0.084	36.3	0.097	0.12
Hydrocarbon Pore Volume Factor[a] (North Area)		6.071			5.098	
Ratio of [b] North Area to Unit Hydrocarbon Pore Volume		67.5/32.5			65.8/34.2	

[a] Sum of (Net Pay x Porosity fraction x (1 - Water Saturation fraction)) for the wells, as calculated by the Board.

[b] $\frac{\text{Hydrocarbon Pore Volume Factor (for the area)}}{\text{Total Hydrocarbon Pore Volume Factor (Total east leg)}}$, as calculated by the Board.

[c] Producing wells.

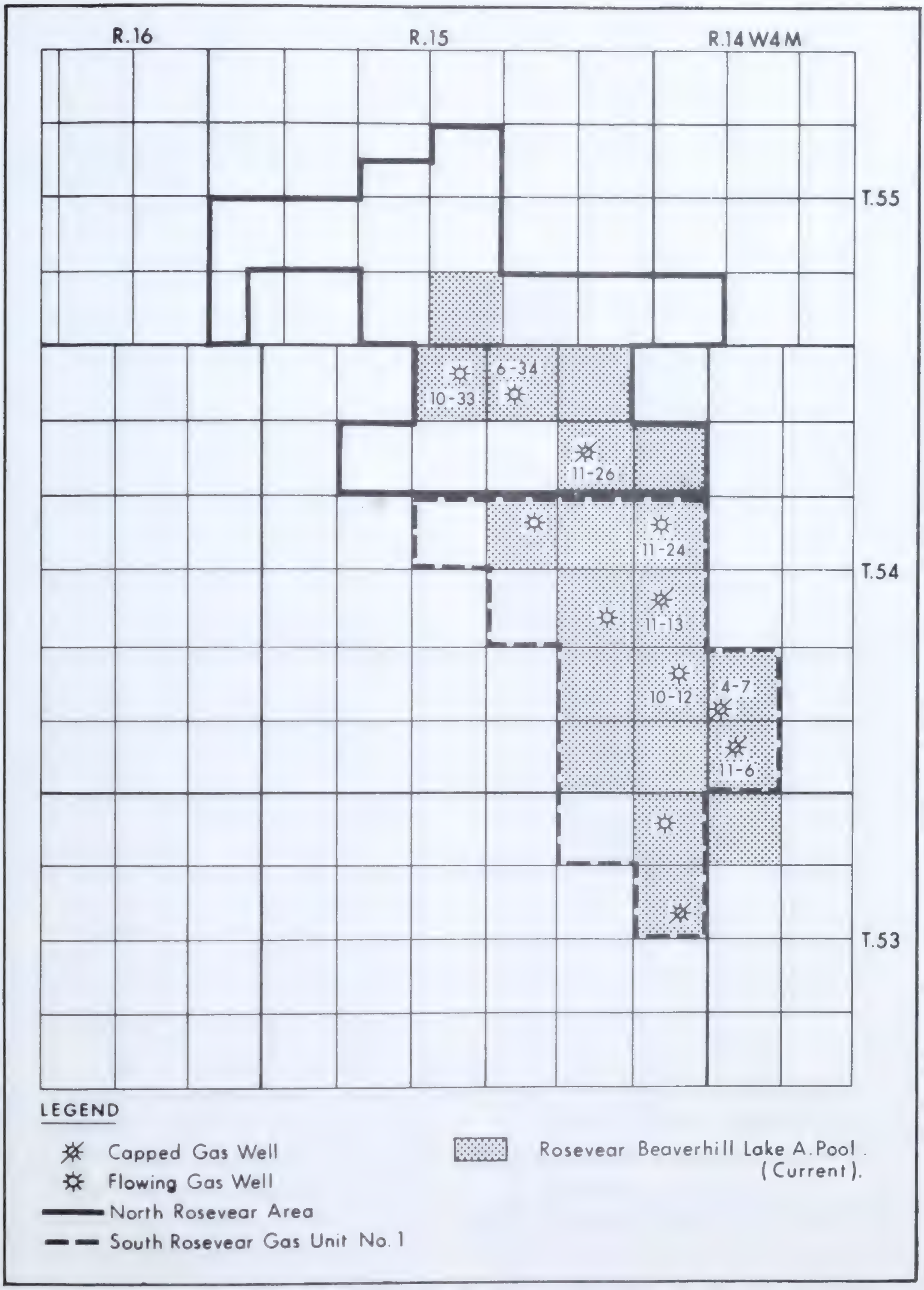


FIGURE 1 EXISTING ROSEVEAR BEAVERHILL LAKE A POOL.
Application No. 840777

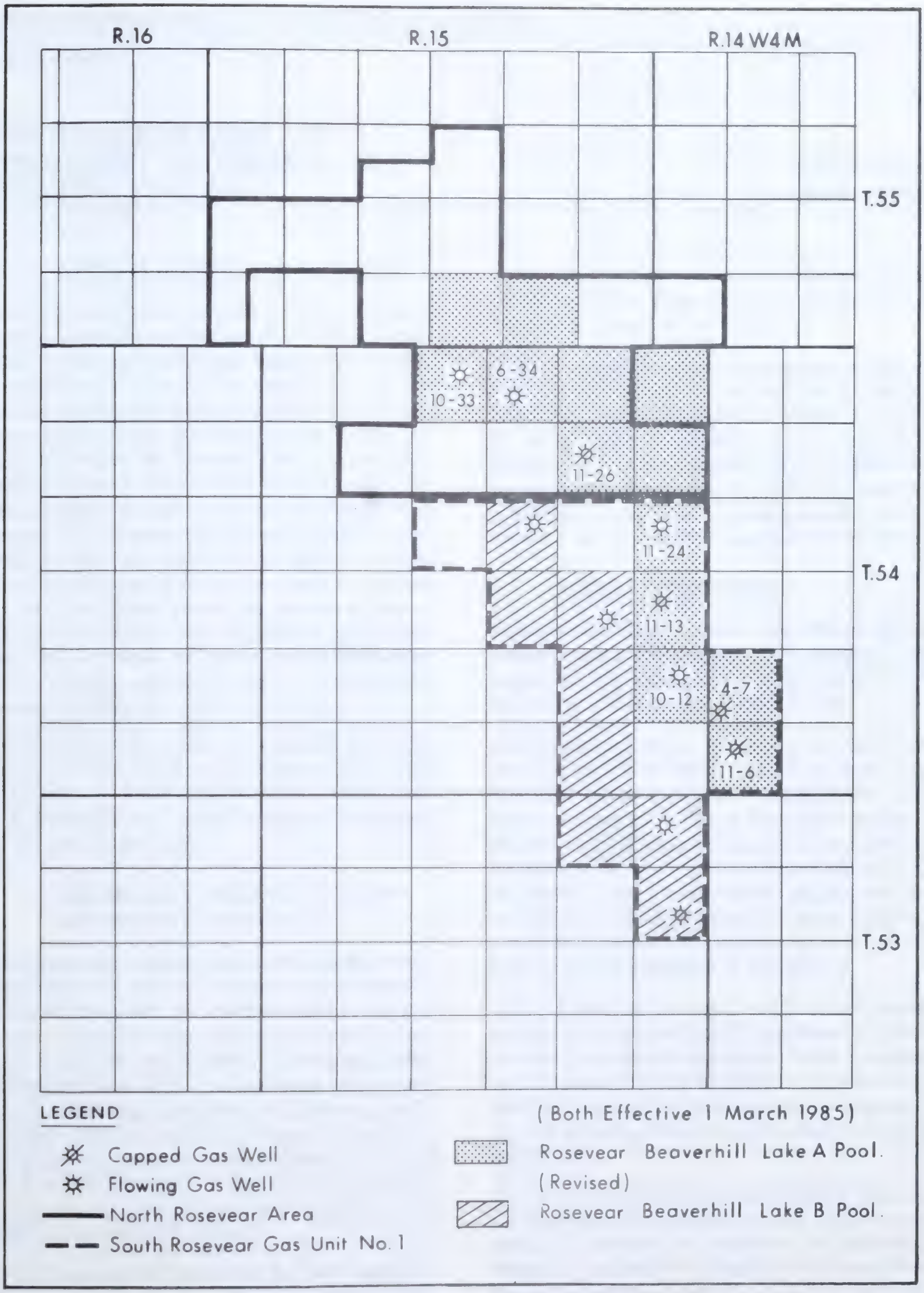


FIGURE 2 AMENDED ROSEVEAR BEAVERHILL LAKE A AND B POOLS.
Application No. 840777

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

BOW RIVER PIPE LINES LTD. APPLICATION TO CONSTRUCT A CRUDE OIL PIPELINE

Decision D 85-12
Application 850027

1 THE APPLICATION AND HEARING

Bow River Pipe Lines Ltd. (Bow River) applied for a permit to construct approximately 27.8 kilometres (km) of 219.1-millimetre (mm) outside diameter (OD) pipeline (the Chin Coulee extension) to transport crude oil from an existing battery site in legal subdivision 15 of section 20, township 7, range 14, west of the 4th meridian, to an existing Home Oil Company Limited (Home Oil) crude oil pipeline in Lsd 13-6-6-12 W4M. The oil would then be moved through the Home Oil pipeline to a Murphy Oil Company Ltd. (Murphy) pipeline in the Milk River area, and from there into the United States. Bow River also applied for an amendment to Licences No. 4912 and 5264 to reverse the direction of flow in a portion of its existing crude oil gathering system from Lsd 7-24-13-15 W4M to Lsd 15-20-7-14 W4M. The route of the proposed pipeline, and related existing and proposed facilities, are shown on the figure.

The application was considered at a public hearing in Calgary, Alberta, on 14 and 15 February 1985, with G. J. DeSorcy, P.Eng., N. A. Strom, P.Eng., and L. A. Bellows, P.Eng., sitting. Participants at the hearing are listed in the table.

2 THE MURPHY INTERVENTION AND ALTERNATIVE PROPOSAL

Murphy submitted an application to the National Energy Board (NEB) for approval to construct approximately 45 km of 219.1-mm OD crude-oil pipeline from a proposed truck terminal and pump station at Lsd 13-32-6-16 W4M near Wrentham to existing Murphy facilities near Milk River. The application was the subject of an NEB hearing commencing 5 February 1985. During the NEB hearing, Murphy amended its application to include construction of an additional 4.5 km of 168.3-mm OD pipeline from the proposed Wrentham pump station to a tie-in point with an existing Bow River pipeline in section 16-7-16 W4M.

Murphy supported that part of the Bow River application respecting the reversal of flow in a portion of the Bow River system, and requested that, if it receives NEB approval of its application, the Board direct that the reversal be extended to Murphy's proposed point of connection to the Bow River system and that the tie-in to Murphy's proposed line be carried out.

Murphy opposed Bow River's proposal to construct the Chin Coulee extension because both the Murphy and Bow River proposed pipelines are intended to provide for transportation of southern Alberta crude oil to Montana markets, and both parties have determined that only one system should be built. Murphy contended that its proposal is more economic, orderly, and in the public interest than the alternative proposed by Bow River.

3 OTHER INTERVENERS

Home Oil intervened in support of Bow River's application and gave evidence regarding the operation of its Legend to Milk River portion of the proposed Bow River-Home Oil integrated pipeline system.

PanCanadian and Norcen, producers of Bow River type crude oil, and Petro-Canada, a major purchaser of the Bow River "A" stream, opposed the application on the basis that a reversal of flow in the southern portion of the Bow River system may have an adverse effect on the quality of the crude oil that is delivered to refineries in Eastern Canada. The interveners contended that such an effect on the quality of the crude oil stream could have a negative impact on the marketability of the oil and result in shut-in production in the Province.

Oakwood stated that its interest was in seeing a pipeline to move Bow River oil to the United States as soon as possible. It considers the Murphy proposal to be a sound one, and appeared to take a position in opposition to the Bow River application, out of concern that approval of it could delay the time to when a pipeline would be available.

CENEX gave evidence regarding its requirements for Canadian crude oil for feedstock at its Laurel, Montana, refinery, its proposal for construction of a pipeline in Montana to receive the crude oil at the international border, and confirmed that a 2-year export licence for 1900 cubic metres per day (m^3/d) to satisfy its requirements had been issued by the NEB.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Bow River Pipe Lines Ltd. (Bow River) K. F. Miller	F. Janzen, P.Eng. Bryan Singleton, P.Eng. D. Fedoration, P.Eng. H. Hicklin, P.Eng.
Murphy Oil Company Ltd. (Murphy) J. R. Smith	I. Reinhart J. Kerz, P.Eng. D. Urquhart, P.Eng. M. Crowley, P.Eng.
Farmers Union Central Exchange (CENEX) F. M. Saville	D. Waddell L. Brown J. Wassen
Home Oil Company Limited (Home Oil) C. A. Keck	W. A. Jackson, P.Eng. Barry Singleton, P.Eng.
Norcen Energy Resources Limited (Norcen) G. E. Sears	
Oakwood Petroleums Ltd. (Oakwood) R. V. Mays A. N. Boyse	A. N. Boyse
PanCanadian Petroleum Limited (PanCanadian) P. R. Murray	
Petro-Canada Inc. (Petro-Canada) W. J. Hope-Ross	G. Hammond C. J. Domansky
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff H. R. Hansford A. Cassley, P.Eng. D. Fraser B. Burgess	

Alberta Environment, through questioning, sought to ensure that the stripping and conservation of topsoil would conform with sound reclamation practices.

4 PRELIMINARY MATTER

Murphy in its submission and during presentation of its closing statement requested the Board to direct, in the event Murphy receives a certificate from the NEB to construct its proposed pipeline, the following:

a) reversal of the flow in a portion of the Bow River crude oil gathering system (existing Licence No. 4912) from Fincastle station (Lsd 14-7-9-15 W4M), or if volumes dictate, from Hays station (section 24-13-15 W4M) to a proposed point of tie-in with Murphy's proposed pipeline system in section 16-7-16 W4M;

b) installation of a pumping station at Lsd 12-6-8-15 W4M to facilitate the flow reversal, and to pressurize a reversed section of Bow River's pipeline from that location to section 16-7-16 W4M.

The request was made pursuant to section 34 of the Pipeline Act chapter P-8, RSA 1980.

The Board questions whether it has the jurisdiction under section 34 to direct the changes to the existing Bow River pipeline system as requested by Murphy. In any case, the subject hearing was not called for that purpose, and the Board is not prepared to consider the request in this report.

5 THE ISSUES

The Board considers the issues to be

1. The need for the pipeline.
2. The ability of the revised system to serve the market.
3. Economics of serving the market.
4. Routing and environmental impact.
5. Technical aspects.
6. The impact on the marketability of Alberta crude oil.

With respect to issues 2 to 6, the Board believes it should consider not only the acceptability of the Bow River proposal, but also a comparison of it, in a general sense, to the alternative system which was discussed by Murphy at the hearing. If the Board is satisfied that the Bow River proposed pipeline system is acceptable and in the public interest, and that it has no serious deficiencies when compared to the Murphy alternative, it would be prepared to approve it, whether or not the NEB approves the Murphy application. If approvals for both systems are issued, the Board expects the market-place and business interests would dictate which line is built. In the Board's judgement, this would be quite appropriate and in keeping with the public interest.

6 NEED OF THE PROJECT

Bow River indicated the existence of both current and future potential markets for Bow River type heavy crude oil as feedstock for Montana refiners. It also submitted that volumes of up to 2400 m^3/day of Bow River crude oil have been transported by truck to the Rangeland pipeline system for shipment to Montana markets. The facilities proposed are intended to eliminate all or most of the current trucking and to allow an alternative to Eastern crude oil movements which could be restrained due to capacity limitations on other pipelines.

The Board is satisfied that there is a need for a pipeline which would move Bow River crude oil directly into the Montana market, thus eliminating a great deal of more expensive trucking.

7 ABILITY TO SERVE THE MARKET

The key market factor associated with this proposal is centred on the 2-year export licence issued to Dome Petroleum Limited as agents for CENEX of Laurel, Montana. CENEX stated its requirement that the pipeline be available to start up by 1 July 1985, to coincide with its licence. It described its preferences for consistency and for a minimum amount of condensate, in the crude oil to be moved, and also for a system that is cost efficient and accessible for future growth potential.

Bow River stated that it can comply with all of the conditions of the purchaser and Murphy also indicated compliance to these conditions by its alternative.

The Board considers the Bow River proposal to be acceptable in terms of ability to serve the intended market. Additionally, the Board perceives no substantial difference in either the Bow River or Murphy proposals in this regard. However, if the volume requirements substantially increase, the Board considers that the Bow River proposal may have a slight disadvantage compared to the Murphy proposal, in that the Bow River proposal would require additional capacity prior to being able to move similar volumes to those which the Murphy proposal could handle.

8 ECONOMICS OF SERVING THE MARKET

Bow River and Murphy presented capital and operating costs for their respective systems. Both emphasized that a major aspect of their applications was the reduction in the cost of transporting oil to the Montana market.

The Board believes that the Bow River proposal is capable of serving the Montana market in an economic and efficient manner.

The Board is satisfied that either system can reduce substantially the current costs associated with moving Alberta oil to the Montana market. It considers that, when the volumes being transported are low, the Bow River system may have a slight advantage in operating costs. However, the Board believes that there is no substantial difference between the two proposals with respect to capital and operating costs generally.

9 ROUTING AND ENVIRONMENT

Bow River stated that in order to extend the existing pipeline from Lsd 15-20-7-14 W4M to the Home Oil Manyberries pipeline at Lsd13-6-6-12 W4M, a significant route control factor was the crossing of the Chin Coulee. Bow River found a geotechnically satisfactory crossing point which minimized the deviation from a straight line connection between the two locations. The route follows existing rights of way, where possible, and avoids archeological sites, key wildlife areas, residences, and farm buildings.

None of the interveners contested the route selected and Bow River satisfactorily answered the few concerns regarding topsoil conservation raised by Alberta Environment.

The Board is satisfied that the route selected is appropriate and, provided suitable mitigative measures are employed, the environmental disturbance will be minimal and long-term impacts negligible. The Board notes that the linear disturbance of approximately 28 km compares favourably with the 45-km length of the Murphy pipeline.

10 TECHNICAL CONSIDERATIONS

Bow River stated that the 219.1-mm OD pipeline was designed for a maximum capacity of 6200 m^3/d of Bow River crude oil with resulting pressures of 9740 kilopascals (kPa) at Chin Coulee and 345 kPa at Legend. It calculated that the capacity of the reversed existing pipeline system, with one additional intermediate 187-kilowatt (kW) pump station, would be approximately 1900 m^3/d. However, with further modifications, such as looping of the existing system, the throughputs could be increased to 4000 m^3/d. The Bow River crude oil would be blended with Manyberries light-crude oil at Legend, and then shipped through the existing Manyberries 168.3-mm OD pipeline to Milk River. At Milk River, the blend would enter the existing Murphy system for shipment to the Montana market.

Home Oil demonstrated that with a 260-kW pump station at Legend and a similar pump station at the hydraulic midpoint of the pipeline between Legend and Milk River, the Manyberries pipeline had sufficient capacity to carry 2150 m^3/d of Bow River crude oil containing 2 per cent condensate at 0°C. It also showed that by essentially doubling the power of the pumps, the system could handle approximately 3500 m^3/d of the Bow River stream. With the addition of a second storage tank at Legend, Home Oil stated that it could accommodate batching of the Bow River crude oil.

Murphy contrasted the apparent complexity of the Bow River/Manyberries operation with its own proposal which, with one 190-kW pump station at Wrentham, would be capable of transporting 3000 m^3/d of Bow River crude oil at 0°C. It pointed out that a 24-hour-per-day operation of the Bow River/Manyberries system was necessary to achieve the stated capacities and questioned the practicality of such operation.

Both Bow River and Murphy were confident that, given timely regulatory approvals, they could meet a 1 July 1985 start-up date.

CENEX put a good deal of emphasis on its concern about minimizing the amount of condensate in the blend. It agreed that either of the two pipeline systems could provide the volumes authorized for immediate export to meet its requirements.

Other interveners did not express concern about the engineering design of the pipelines.

The Board is satisfied that the Bow River/Manyberries pipeline system is capable of transporting the required volumes under winter conditions, either in a blend of Bow River crude oil and Manyberries light-crude oil or in batch mode. As mentioned previously, if the volumes of oil to be transported increase substantially, the Murphy system would appear to have an advantage.

11 IMPACT ON MARKETABILITY OF ALBERTA CRUDE OIL

Certain producers and a major purchaser of the Bow River crude oil currently moving northward expressed concerns with respect to market acceptance of the north-bound blended crude oil if the proposed project were implemented. Their concerns focused on the affects on crude-oil quality and ultimately the Bow River stream marketability, if the higher asphaltene-content crude-oil sources located in the southern area of the Bow River system were diverted to the south in the reversed portion of the system and thus removed from the north-ward stream.

Petro-Canada supplied the results of tests carried out on samples of blends of Bow River crude oil which excluded oil from the southern end of the system.

The tests indicated adverse effects on the asphaltene content to the extent that, if the reversal became a reality, Petro-Canada would no longer purchase the 4370 m^3/d that it is currently taking. A request was made for a delay in the Board's decision until further detailed testing of the effects of the Bow River proposal could be undertaken.

The Board has given due consideration to the concerns expressed by certain producers and Petro-Canada as a purchaser, and recognizes that the sampling evidence identifies a potential problem. However, the data provided by Petro-Canada, by its own evidence, is not conclusive, because of the time constraints placed on the sampling and analysis techniques. Even if the evidence were conclusive, the Board is of the view that in a deregulated oil marketing system, the supply and demand situation and the pricing flexibility would be such that the Bow River crude oil would likely find an appropriate purchaser somewhere in the market-place. The Board questions whether it would be appropriate, in a deregulated system, for it to attempt to protect a particular stream for an individual purchaser. Therefore, the Board is not prepared to defer or make its decision conditional in regard to this issue.

In addition, it is worth noting that Bow River indicated that if its proposal were otherwise to go ahead, and if further sampling and analysis showed that reversal of its system would seriously jeopardize operation of its pipeline system to the north, it would not undertake the project.

12 DECISION

The Board approves Application 850027 by Bow River Pipe Lines Ltd., and is prepared to issue a permit for a new pipeline and to amend two existing pipeline

licences. The approving documents will be issued upon receipt of the necessary approval from the Minister of the Environment respecting environmental matters.

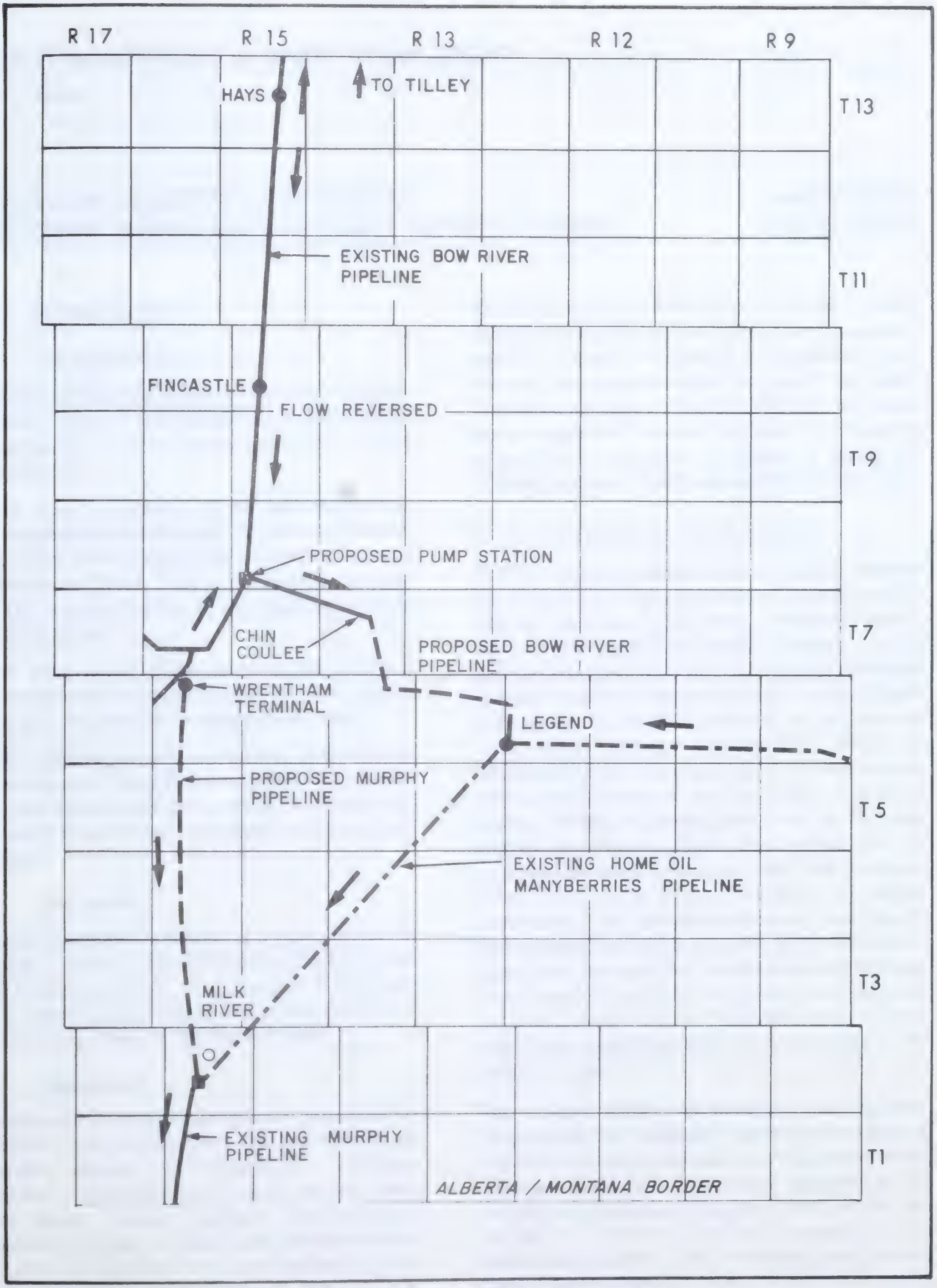
DATED at Calgary, Alberta, on 22 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

N. A. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Board Member



BOW RIVER PIPELINE LTD. APPLICATION NO. 850027

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

TRANSALTA UTILITIES CORPORATION BOW RIVER HYDRO DEVELOPMENT MODIFICATIONS

Decision D 85-13
Application 840943

1 INTRODUCTION

1.1 The Application

TransAlta Utilities Corporation (TransAlta) applied, pursuant to section 7 of the Hydro and Electric Energy Act and section 19 of the Hydro and Electric Energy Regulation, for

(a) the Board's acceptance of the computations and conclusions set out in a report prepared by Monenco Limited, dated August 1984 and entitled Probable Maximum Flood Study for TransAlta Utilities' Hydroelectric System, as they relate to the Bow River system;

(b) an order of the Board approving the proposed modifications to the Bearspaw Hydro Development to pass the probable maximum flood flow;

(c) the Board's approval, in principle, of the need to increase spill capacities at the Ghost and Cascade hydro developments and to modify the Ghost Diversion to accommodate the probable maximum flood flows.

1.2 The Hearing

The application was considered at a public hearing in Calgary, Alberta, on 20 February 1985, with C. J. Goodman, P.Eng., V. E. Bohme, P.Eng., and N. A. Strom, P.Eng., sitting. Those who appeared at the hearing are listed in the attached table.

1.3 Background

TransAlta constructed 11 hydroelectric projects in the Bow River basin between 1911 and 1960 with a total generating capacity of 325 megawatts. They are Horseshoe, Kananaskis, Ghost, Cascade, Barrier, Spray, Three Sisters, Rundle, Bearspaw, Interlakes, and Pocaterra (see Figure 1). Each project was designed and constructed in accordance with good engineering practice at the time of the development. TransAlta has operated these facilities since completion and, in accordance with section 40 of the Hydro and Electric Energy Act, TransAlta is deemed to be the holder of an order of the Board for each of these 11 hydro developments. TransAlta is also a licensee for each of these 11 hydro developments under the Water Resources Act administered by Alberta Environment. In September 1978, Alberta Environment issued a Dam and Canal Safety Regulation pursuant to that Act. The Dam and Canal Safety Regulation Guidelines stipulate that any existing or new large dams must be capable of passing the probable maximum flood without failure of the dam.

2 APPLICANT'S SUBMISSION

In 1978, TransAlta retained Monenco Limited to undertake a hydrology study to determine the adequacy of all existing TransAlta hydro dams to withstand floods, using current engineering practice. Monenco Limited was also asked to develop an overall strategy, including remedial measures, required at each existing hydro development to meet the provisions of the Dam and Canal Safety Regulation Guidelines. The study was completed in 1984 and the study methods, computations, results, and conclusions were presented in a report entitled Probable Maximum Flood Study for TransAlta Utilities' Hydroelectric System, dated August 1984. As a result of the study, it was determined that Bearspaw, Ghost, and Cascade (Ghost Diversion is an integral component of the Cascade development) were the only developments not capable of passing the probable maximum flood flows and that therefore required remedial work. Detailed designs for the remedial work proposed at Ghost, Cascade, and the Ghost Diversion are under way. Upon completion, they will be submitted to the Board for approval.

The existing spillway at Bearspaw was originally designed and built to handle a maximum flood flow of 100 000 cubic feet per second (cfs) while the probable maximum flood flow is currently calculated to be 217 000 cfs. With a flood flow greater than 100 000 cfs, the reservoir level would rise until overtopping of the earthfill dam occurred. This overtopping would in turn cause a failure of the dam by rapid wash-out of the fill material and the water stored in the reservoir would flow out in a short-duration flood crest. It is estimated that the rise in water level at the 85th Street bridge would be in the order of 7 feet in a period of 35 minutes, and

the dam-failure flood crest could cause loss of life and property damage over and above that already suffered in the natural flood.

TransAlta has completed detailed engineering for the necessary remedial work at Bearspaw. It proposes to construct a free overflow weir and discharge channel at the north abutment and to raise the existing earthfill dam by 4 feet as indicated in Figure 2. Since TransAlta owns all the lands in the development area, no landowners would be directly affected. The only known environmental impact is the possibility of minor siltation of a very localized quiescent area of the reservoir during construction of the cofferdam. Fish spawning activity downstream of the dam would not be affected.

TransAlta presented two alternative construction schedules. Alternative One would allow an April 1985 start of construction with work completed by the spring of 1986. Alternative Two would start construction in August 1985 and complete in the fall/winter of 1986. The applicant prefers Alternative One due to the advantages of reducing by 1 year the risk of dam failure as a result of excessive large flood flow, and also due to some minor savings on cost. The total estimated cost for the proposed work is about $14 000 000, which would have a positive although small impact on the local construction industry.

During the first 2 months of Bearspaw spillway construction, the reservoir level would be lowered from an elevation of 3578 to 3565 feet to permit construction of the cofferdam. TransAlta will advise every licensed reservoir water user by letter of the proposed reservoir elevation changes. The applicant stated it is prepared to provide assistance to every licensed reservoir water user in meeting normal water requirements during the reservoir drawdown period.

In response to Alderman Hodges' concern regarding potential controversy as to the truck routes to be used by concrete transit mix trucks, TransAlta said it would include a clause in its tender specifications to avoid such problems.

3 INTERVENERS' SUBMISSIONS

Glenbow Ranching Ltd. and Damkar Brothers are both licensed to draw water for irrigation purposes from the Bearspaw reservoir, and generally do so from mid May to mid September. Reservoir drawdown during this period would interfere with their operations. However, they would not object to such drawdown if TransAlta provided assistance to help them meet their irrigation water requirements.

Alderman Hodges raised the concern that the successful bidder for the contract to supply concrete to the project may wish to use the 85th Street bridge as a truck route, and this could cause controversy in the neighbouring communities and conflict with the existing truck route by-law.

4 DECISION

The Board announced the decision set out below following a short recess at the conclusion of the hearing.

The Board has considered the evidence in support of Application 840943 by TransAlta Utilities Corporation pursuant to section 7 of the Hydro and Electric Energy Act and section 19 of the Hydro and Electric Energy Regulation, as well as the evidence filed by the interveners and the argument submitted by the parties, and the commitments by TransAlta to assist the licensed reservoir water users. The Board finds as follows:

(a) the Board accepts that the Monenco Limited study filed by the applicant provides adequate evidence of a need for modifications to some of the Bow River hydroelectric system developments;

(b) the Board accepts, in principle, the need for modifications to the spill capacities at the Ghost and Cascade sites, and to the Ghost Diversion, as generally described in the application, but is unable to approve these modifications until the specific applications are before the Board; and

(c) the Board finds that the applied-for modifications to the Bearspaw Hydro Development are appropriate and necessary in the public interest and for public safety.

Therefore, the Board approves the applied-for modifications to the Bearspaw Hydro Development as described in the application, with a construction schedule as set out in Alternative One for completion early in 1986.

DATED at Calgary, Alberta, on 27 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman, P.Eng.
Board Member

V. E. Bohme, P.Eng.
Board Member

N. A. Strom, P.Eng.
Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
TransAlta Utilities Corporation (TransAlta) J. B. Malone	W. Saponja, P.Eng. R. A. Keys, P.Eng. J. A. Randle, P.Eng. H. S. Williams, P.Eng.
Glenbow Ranching Ltd. N. Harvie	N. Harvie
Damkar Brothers E. Damkar	E. Damkar
Alderman Dale Hodges	D. Hodges
Energy Resources Conservation Board staff Ann A. Gervais J.N.G. Yu, P.Eng. R. Schroeder	

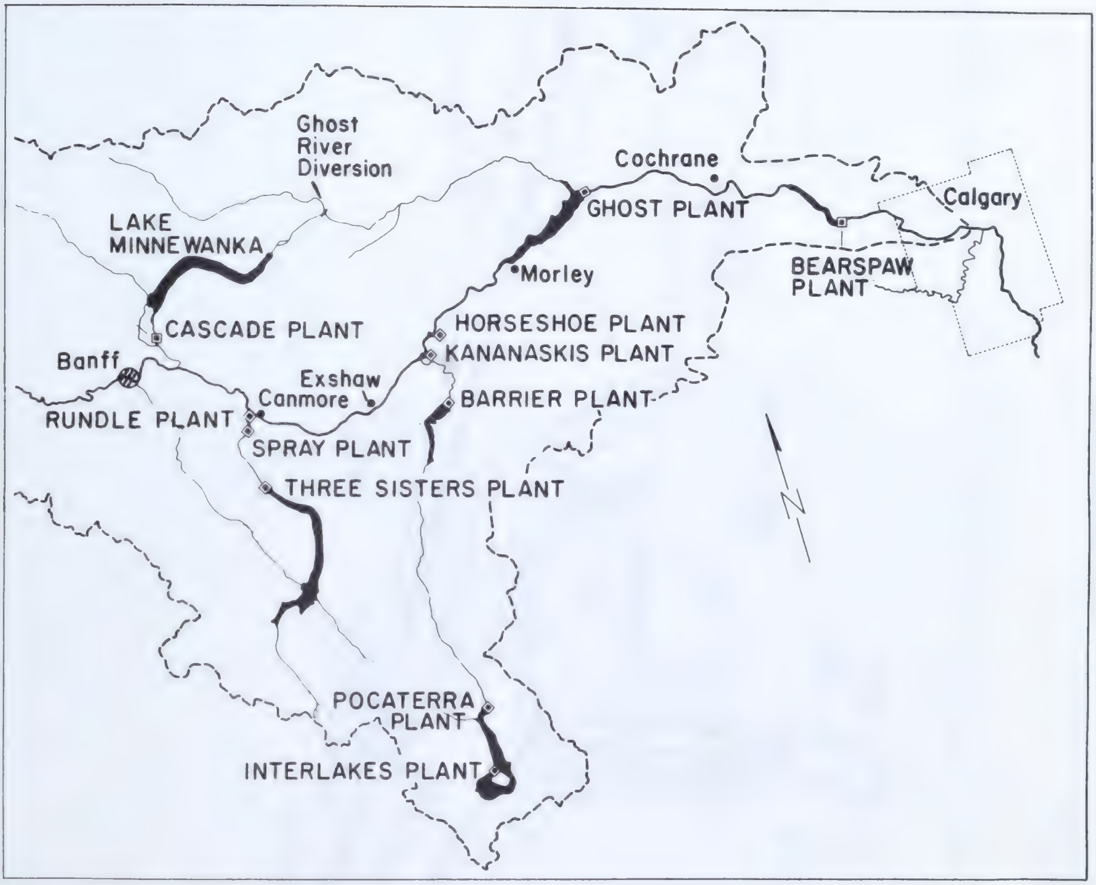


FIGURE 1
BOW RIVER AREA
TRANSALTA UTILITIES CORPORATION
EXISTING HYDRO DEVELOPMENTS
BOW RIVER BASIN

D 85-13
ERCB

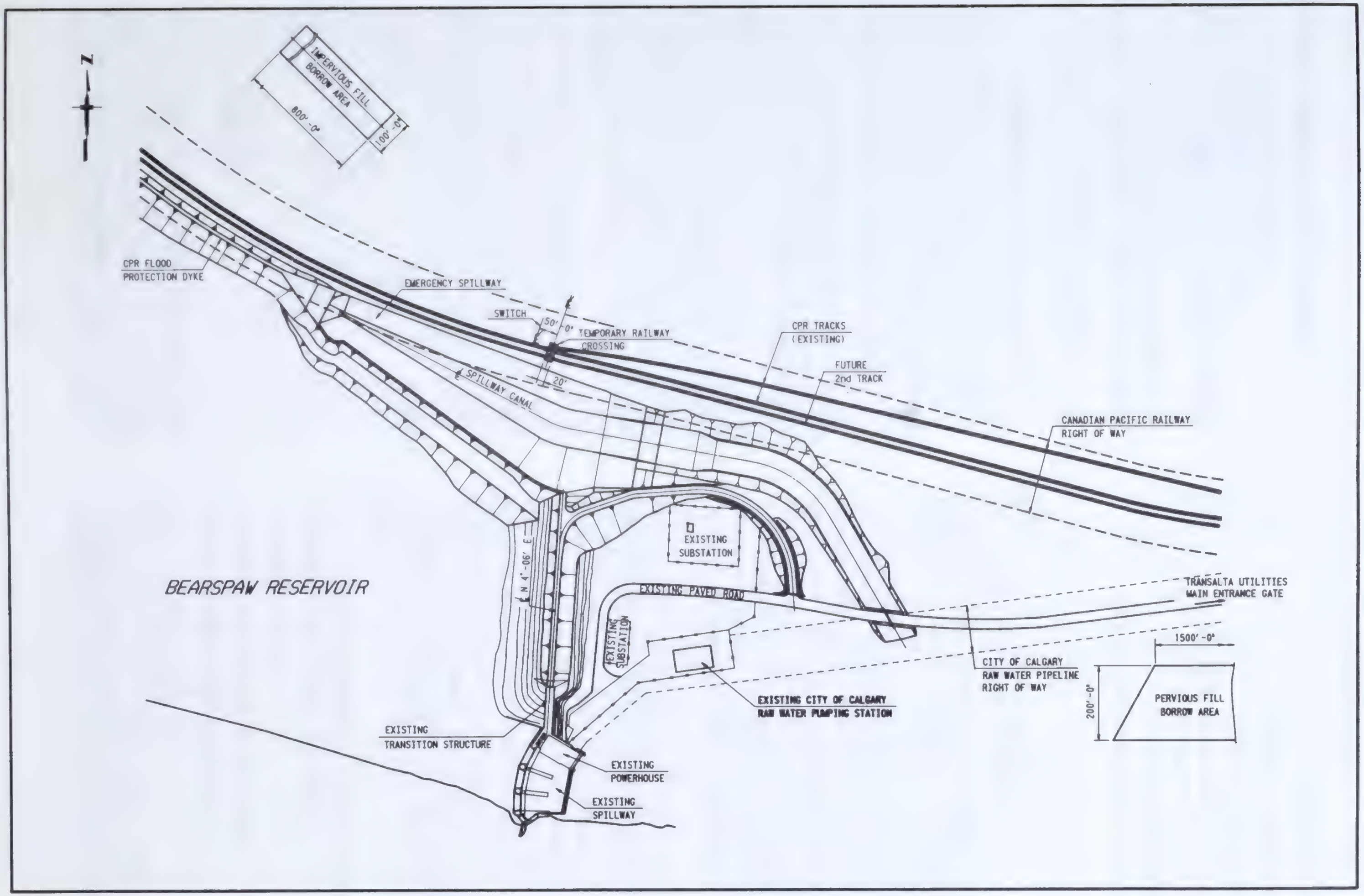


FIGURE 2
WEST CALGARY AREA
TRANSALTA UTILITIES CORPORATION
PROPOSED MODIFICATION TO BEARSPAW HYDRO DEVELOPMENT

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

DOME PETROLEUM LIMITED

Decision D 85-14

GAS CYCLING SCHEME — APPLICATION 840607
GAS PROCESSING PLANT — APPLICATION 840816
SOUR GAS PRODUCTION PIPELINES — APPLICATIONS 841010 AND 841011
FUEL GAS PIPELINES — APPLICATIONS 841012 AND 841013
SOUR GAS INJECTION PIPELINE — APPLICATION 841014
SWEET GAS INJECTION PIPELINES — APPLICATIONS 841015 AND 841016

LA GLACE — WEMBLEY AREA

1 INTRODUCTION AND HEARING

Dome Petroleum Limited (Dome) submitted nine applications pursuant to the Oil and Gas Conservation Act and Regulations and the Pipeline Act and Regulations for approval to construct a gas gathering system, a gas processing plant, and to initiate a gas cycling scheme in the La Glace — Wembley area.

Figure 1 (attached) shows the location of existing wells, batteries, proposed wells and pipelines, the proposed gas plant, and certain geographical features of the area.

Since Dome's applications came forward at approximately the same time and as they are all integral components of an overall energy development scheme proposed for the area, the Board considered the applications at one hearing and is reporting on them in this report.

A description of each application appears at the beginning of the respective sections of the report, along with a listing of the issues arising from each specific application. The section on each application appears in the same order as shown on the title page. For convenience, a brief table of contents follows:

The applications were considered at a public hearing in Grande Prairie, Alberta, on 15 and 16 January 1985, with V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and F. J. Mink, P.Eng., sitting. Those who appeared at the hearing are listed in Table 1 below.

2 APPLICATION 840607 — GAS CYCLING SCHEME

Dome, on behalf of itself and all working interest owners (see Table 3), submitted Application 840607 pursuant to section 26 of the Oil and Gas Conservation Act for approval of a gas cycling scheme in the gas cap of the Valhalla Halfway B Pool and the Wembley Halfway B Pool (B Pool). The pool extends some 21 kilometres (km) in length and underlies both the Valhalla and Wembley fields. Figure 2 (attached) shows that the pool is comprised of an oil sector mainly in township 72, range 8, west of the 6th meridian, and a gas cap mainly in townships 73 and 74.

Dome proposed a partial gas cycling scheme to produce a maximum of 1690 thousand cubic metres per day ($10^3m^3/d$) of raw gas, remove associated hydrocarbon liquids, and inject sufficient residue gas to maintain a cumulative gas cap voidage replacement ratio (VRR) of 0.75. The raw gas would be processed at the proposed Wembley gas plant. The acid gas removed at the proposed gas plant would be diluted with sweet residue gas and injected into a localized portion of the B Pool gas cap. Sweet residue gas would be injected in the remainder of the gas cap.

2.1 Issues Regarding the Cycling Scheme

The Board considers the issues to be:

- need for cycling,
- suitability of the proposed scheme, and
- effect of scheme on oil production.

2.2 Applicant's Views

Dome stated that the B Pool gas cap is a retrograde condensate reservoir presently at its dew-point. It contended that primary depletion of this reservoir

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Dome Petroleum Limited (Dome) F. M. Saville, Q.C.	R. I. Bohach, P.Eng. E. L. Forgues, P.Eng. P. J. Grant, P.Eng. H. R. Jeffers, P.Eng. A. M. Johnston, C.E.T. W. H. King, P.Eng. T. P. McGlynn J. R. Moore, P.Eng. H. W. Petranik, P.Eng. G. A. Webster, P.Eng.
Total Petroleum Canada Ltd. (Total) B. G. Hilchey	G. V. Collins, P.Eng. D. B. Shantz, P.Eng.
Alberta Gas Ethylene Company Ltd. (AGEC) F. Foran	
Atcor Resources Limited (Atcor) D. M. Murray, P.Eng.	
Chieftain Development Co. Ltd. (Chieftain) R. C. Draper, P.Eng.	
Dow Chemical Canada Inc. (Dow) F. Foran	
Ocelot Industries Ltd. (Ocelot) C.L.K. Higgens	
PanCanadian Petroleum Limited (PanCanadian) E. S. Decter	
Petro-Canada Inc. (Petro-Canada) W. J. Hope-Ross	
Sulpetro Limited (Sulpetro) S. Devaleriola, P.Eng.	
South Peace Regional Planning Commission (SPRPC) J. A. Simpson	
Bear Lake Farm Rights Group Central Peace Farm Rights Group (Farm Rights groups) J. D. Carter	
Alberta Environment D. L. Bratton, P.Eng. C. S. Liu, P.Eng.	
Energy Resources Conservation Board staff H. R. Hansford M. Semchuck, C.E.T. B. C. Hubbard, P.Eng. A. Varma, C.E.T. H. W. Knox, P.Eng. T. Walden	

Canadian Hunter Exploration Ltd., Ladd Exploration Company, and Texaco Canada Resources Ltd. filed interventions but did not appear at the hearing.

would result in a significant loss in hydrocarbon liquid recovery, and therefore a gas cycling scheme is necessary to maximize hydrocarbon recovery from the gas cap.

Dome acknowledged that full cycling would yield a marginally higher liquid recovery but stated that the increased liquid recovery would not offset the costs of purchasing make-up gas for full cycling. It believed the proposed scheme of 0.75 VRR to be more attractive as it allowed substantial economic benefits from partial gas sales. Dome noted that there is some potential for extension of the B Pool but claimed that this would not substantially affect the scope of the project. It stated that the production/injection pattern as shown in Figure 2 would optimize hydrocarbon recovery from the B Pool gas cap.

Dome stated that the proposed cycling scheme would maintain original pressure at the gas-oil interface by meeting or exceeding full voidage replacement in this region and thereby minimize the effect on oil recovery. Dome added that the potential problem of injection gas breakthrough to oil wells outside the unit has been recognized and discussed with PanCanadian and Total, the other two oil pool operators. Dome said that all three oil pool operators had submitted a ''letter of intent'' regarding future operations in the B Pool to the Board, and that the inclusion of the first row of oil producers into the unit was being considered as well as other scenarios. It noted that all oil pool operators also have a working interest ownership in the gas cap. Dome added that unitization discussions are currently in progress and it expects these negotiations to be completed before plant start-up.

2.3 Interveners' Views

The interveners did not express any concerns regarding the cycling scheme.

2.4 Board's Views

The Board concurs with Dome that due to the retrograde nature of the gas cap fluid, primary depletion of the B Pool would result in a substantial loss of hydrocarbon liquids. The Board therefore agrees with Dome that a gas cycling scheme is required to optimize hydrocarbon recovery from this pool.

Regarding the suitability of the proposed scheme, the Board considered both the hydrocarbon recovery and the economics of partial and full cycling and believes the proposed partial cycling scheme and the proposed production/injection configuration represents an acceptable mode of depletion for the B Pool gas cap.

The Board notes that negotiations towards unitizing the gas cap are progressing and expects the gas cap to be unitized prior to implementation of the scheme.

The Board is satisfied that full pressure maintenance at the gas-oil interface should mitigate possible detrimental effects of gas cap production on oil recovery. The Board understands that Dome, PanCanadian, and Total, having common working interests in both the gas cap and the oil pool, have agreed to formulate an equitable and workable arrangement to handle gas cap gas breakthrough into oil wells outside the project area.

3 APPLICATION 840816 — THE GAS PROCESSING PLANT

Dome applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct a sour gas processing plant to be located in legal subdivision (Lsd) 6 of section 19, township 73, range 8, west of the 6th meridian (6-19).

The plant would be designed to process a maximum of 2803 × $10^3 m^3/d$ of raw gas from the B Pool along with solution gas from various oil batteries in the vicinity of the plant.

The facility would produce residue sales gas, a liquefied petroleum gas (LPG) mixture composed primarily of propane and butanes, a natural gas liquids (NGL) mixture composed primarily of ethane, propane, and butanes, and a stabilized condensate product which would be a mixture mainly of pentanes and heavier hydrocarbons. Plant products would consist of a maximum of 822 × $10^3 m^3/d$ of sales gas, 1395 m^3/d of NGLs, 401 m^3/d of LPGs, and 660 m^3/d of stabilized condensate.

Under normal operating conditions, Dome would inject all the acid gas from the proposed plant back into a localized portion of the reservoir through injection wells described in the cycling scheme application. Following a 12- to 15-year gas recycle and hydrocarbon liquid recovery period, acid gas injection would cease. At that time, Dome would make application to the Board to construct and operate a sulphur recovery plant having a projected maximum daily sulphur inlet rate of approximately 27.7 tonnes per day (t/d).

3.1 Issues Regarding Plant Operations

The Board considers the issues respecting the plant operations portion of the application to be:

- the need for and size of the plant,
- conservation benefits, and
- impact of the proposed plant.

3.2 Applicant's Views

Dome stated that a gas processing plant is needed to process sour gas from the B Pool gas cap and the currently flared sour solution gas from two nearby central oil batteries and other single-well batteries in the La Glace — Wembley area.

Dome said that its plant would have sufficient capacity to accommodate all the known sour gas reserves in the area of the B Pool gas cap. Dome stated that it provided adequate spare capacity in designing the plant to account for the possibility that other volumes of solution gas in the general area would require processing at its facility.

In response to questions by the Farm Rights groups regarding the participation of other energy operators in its scheme, Dome stated that other gas owners in the area who chose not to participate in Dome's scheme may have done so for economic reasons. Dome indicated that two of its own single-well batteries in the area would not be tied into the plant's gathering system because low gas rates made their inclusion uneconomic. However, with respect to the overall conservation benefits, Dome said that its plant would eliminate the need to flare most of the sour solution gas in the vicinity of its plant, would result in the conservation of a valuable resource, and would thereby allay many of the area residents' concerns about the flaring of solution gas at field facilities in the area.

Dome claimed that the plant would not cause any significant environmental impact. The plant site had been acquired without any complications and it knew of no objections to the plant's location.

Dome investigated various alternatives for supplying electricity for its processing facility, including self-generated power at the plant but concluded there was a very clear economic advantage in favour of purchasing power from Alberta Power Limited (Alberta Power). Dome confirmed that its study to supply power to the plant was based only on economics and did not take into account the possible impact on area residents who may be affected by an additional powerline that would be required.

Dome stated it did not anticipate any technical problems with respect to acid gas injection. Two sour gas injection compressors would be installed, each being capable of handling the entire volume of acid gas to be injected. This arrangement would ensure that while one compressor was operating, service and maintenance could be carried out on the other unit. Dome expressed confidence in the reliability of its proposed acid gas injection scheme.

Dome said that because the acid gas composition varies considerably, from 200 parts per million (ppm) to 11 000 ppm of hydrogen sulphide (H_2S), designing a sulphur recovery plant would be difficult at the present time in terms of proper sizing. Dome stated that following the completion of the acid gas injection phase, the acid gas composition would be well defined and this would allow for optimum sulphur plant design. Dome verified it would submit an application to the Board requesting approval to construct and operate sulphur recovery facilities at that time.

3.3 Interveners' Views

All interveners supported Dome's application and concurred that the plant would be needed to serve the cycling scheme and to conserve and process solution gas currently flared in the area.

Total stated that it was a working interest owner in Dome's cycling scheme. Total said it had four separate projects in the area which would require gas processing capacity and could result in four separate gas plants in the absence of the proposed plant. Total supported a single centrally located and adequately designed plant rather than several smaller plants and said Dome's proposed scheme would preclude the proliferation of gas plants. Total stated that the proposed plant should be built to conserve solution gas currently flared and added that this would likely reduce the nuisance and inconvenience presently experienced by area residents.

The Farm Rights groups questioned Dome as to why operators in the Grande Prairie Field, who are also flaring sour solution gas at field batteries, are not participating in Dome's scheme. The Farm Rights groups also questioned whether Dome had designed the plant appropriately, stating that they did not wish to see a situation arise where other gas owners could claim that their sour gas could not be conserved because there was no spare processing capacity at Dome's plant. The interveners agreed with the applicant regarding the conservation benefits that would be gained from the operation of Dome's plant.

With respect to the impacts of the plant, the Farm Rights groups stated that purchasing power for the proposed plant would result in Alberta Power having to construct a new powerline in the area. They claimed this would adversely affect the area residents by disrupting their farming operations and would create visual impacts. The Farm Rights groups suggested that, as an alternative to purchasing power, the power supply required by the plant could be

self-generated using the currently flared solution gas in the area as fuel.

The Farm Rights groups concurred with Dome's proposal to inject acid gas during the cycling phase of the project.

3.4 Board's Views

The Board agrees that a gas processing plant is required to serve Dome's cycling scheme and that it is in the public interest to gather and conserve the sour solution gas that is currently being flared at batteries near the cycling scheme.

The Board observes that the applied-for 2803 $\times$ $10^3 m^3/d$ capacity of the proposed plant is in excess of that which would be required to process the known raw gas reserves in the La Glace-Wembley area. It notes that Dome has provided spare capacity for processing about 280 $\times$ $10^3 m^3/d$ of additional raw sour gas in the event that other gas becomes available in the area which could be delivered economically to Dome's plant. With the provision of spare capacity and having regard for the area's gas processing requirements, the Board concludes that Dome's plant is appropriately sized and designed to meet the currently known gas processing requirements in the area.

The Board acknowledges the concerns expressed by the Farm Rights groups regarding the present flaring of sour solution gas in the Grande Prairie Field, however, it notes that the field is approximately 24 km east-southeast of Dome's proposed plant and is unlikely to be within the operating sphere of Dome's proposed plant. Dome did not present any specific evidence regarding the economic viability of installing a gas gathering system to conserve and transport solution gas from the Grande Prairie Field. However, the Board notes that Dome contacted all operators in the area and invited them to nominate for capacity at its plant but some, perhaps for economic reasons, chose not to tie in solution gas production from their facilities to Dome's plant. The Board estimated the amount of solution gas currently being flared in the Grande Prairie Field to be in the order of about 20 $\times$ $10^3 m^3/d$. Having regard for the distance from Dome's plant, gas conservation for the field would appear uneconomical at this time.

The Board concludes that air and water quality impacts from Dome's applied-for gas processing plant would be negligible and that the plant's emission rates, which would be specified in the required licences for the plant, would be insignificant.

The Board accepts Dome's evidence that purchasing power from Alberta Power is more practical and economic than generating power on the plant site. Moreover, the Board recognizes that by purchasing power from Alberta Power, Dome would be providing the plant with reliability and operational flexibility. The Board notes that Dome's two acid gas injection compressors would be electrically driven, and with a reliable source of power and a planned maintenance schedule for the compressors, the likelihood of having the acid gas injection operations disrupted would be reduced.

The Board understands that due to the varying concentrations of H_2S in the producing reservoirs, it would be difficult to design processing facilities for the recovery of sulphur at the present time. The Board accepts Dome's evidence that to design and operate a sulphur plant to meet the proposed processing plant's present needs would cost an estimated \$3.6 million. The Board notes that by comparison, Dome's acid gas injection scheme including 895 kilowatts of compression and injection facilities would only cost an estimated \$1.8 million.

The Board believes that Dome's proposal to inject acid gas for about 12 to 15 years is technically sound since it would replace voidage in the reservoir and eliminate the emission of sulphur compounds to the atmosphere. When acid gas injection ceases, the gas cap would be blown down. Approval to construct and operate sulphur recovery facilities would be subject to a separate application to be filed by Dome in the future.

4 EXTRACTION OF ETHANE-PLUS LIQUIDS

Dome proposed to extract a mixture of ethane and heavier hydrocarbons (ethane-plus) from the natural gas to be processed at its proposed Wembley plant. By deep-cutting the gas, Dome would recover a maximum of 1395 m^3/d of ethane-plus liquid which would be made up of approximately 65 per cent ethane, 26 per cent propane, 8 per cent butanes, and 1 per cent pentanes and heavier hydrocarbons.

4.1 Issues Regarding the Extraction of Ethane-Plus Liquids

The Board believes that the following issues must be considered in assessing the public interest of proceeding with the deep-cut facility:

- the incremental recovery of ethane and other natural gas liquids at the proposed facility,
- the present and future markets for the ethane,

- the cost of recovering ethane at the proposed facility compared to costs elsewhere in the province,
- the impact on the existing straddle plants and on the Alberta petrochemical industry,
- the impact on enhanced recovery of oil,
- the economic benefits to Alberta, resulting from the incremental ethane recovery,
- the proprietary rights of gas producers,
- the degree of upgrading of resources within Alberta, and
- the conservation and environmental aspects of the proposed facilities.

4.2 Applicant's Views

Dome indicated that over the period 1986 to 2005, some 2.4 million cubic metres (10^6m^3) of ethane, 1.0 $\times$ 10^6m^3 of propane, and 330 $\times$ 10^3m^3 of butanes would be recovered that would be incremental to the province if the proposed deep-cut facility was utilized. Dome assumed that the ethane recovery efficiency at the existing Empress straddle plants would be equal to the recovery efficiency at the Wembley plant, approximately 80 per cent. Dome said that this assumption implied that no incremental volumes of ethane would be recovered from deep-cutting the sales gas portion of the plant throughput. Dome stated, however, that the expected average ethane recovery efficiency at the Empress straddle plants would not be much higher than 70 per cent.

In response to questions regarding present and future markets for the Wembley ethane-plus liquids, Dome stated that during the initial years, it would be able to use all of the ethane-plus liquids in its own miscible flood schemes. Dome also stated that some of the working interest partners in the project would require their share of the ethane-plus liquids for their own miscible flood projects. For the immediate future, Dome expected that ethane requirements in the province would exceed supply, mainly due to increasing demand in miscible flood operations. Dome indicated that if the miscible flood market could not absorb all of the Wembley ethane-plus liquids during the project life, it would consider displacing volumes of specification ethane that could go to the miscible flood market, fractionating its mix to sell the ethane component to the petrochemical industry, or reinjecting the ethane-plus liquids into the sales gas stream leaving the Wembley plant.

To determine the competitive position of its ethane, Dome calculated that the cost of extracting ethane at Wembley and delivering it to Fort Saskatchewan would be \$38.04/m^3 (excluding shrinkage). This cost would be made up of \$27.04/m^3 for processing at Wembley and \$11.00/m^3 for transportation to Fort Saskatchewan via the Peace Pipe Line Ltd. (Peace Pipe Line) pipeline system. Dome concluded that since its cost of \$38.04/m^3 was less than the comparable cost of the three field plants previously approved by the Board in Decision 82-G[1], its products would be competitive in the market-place. Dome also stated that if only the cycle gas volumes were deep-cut to extract the ethane-plus mix, the processing cost of the ethane component at Wembley would be \$28.94/m^3 (excluding shrinkage).

Dome acknowledged that the field extraction of ethane from sales gas negatively impacts the straddle plant system and petrochemical industry. Dome suggested, however, that the impact associated with the Wembley plant would be minimal for a project of its size. Dome stated that because of the high ratio of recycle gas volume relative to sales gas volume, its project would provide maximum benefit to the province in terms of ethane extraction while minimizing the corresponding impact on the petrochemical industry. In its cost/benefit analysis for the project, Dome calculated that ethane extraction at the proposed Wembley plant would cost the petrochemical industry some \$23 million (undiscounted) over a 20-year period due to the increased cost of ethane extraction caused by lower throughputs of ethane at the Empress straddle plants. In response to questioning, Dome said that there could be an additional cost to the petrochemical industry to the extent that ethane recovered at Wembley would no longer be available for recovery at the Empress straddle plants and therefore not available for export sale. Dome also calculated that deep-cutting at the proposed Wembley plant would impose a cost of \$123 million (undiscounted) on the Empress straddle plant operators over the life of the proposed project because of the reduced volumes of propane-plus liquids that would be available for recovery at Empress.

To reduce the impact of the proposed plant on the straddle plants and petrochemical industry, Dome committed to reinject into the sales gas an amount of ethane-plus liquids equal to the amount that would be extracted by deep-cutting Dome's share of the sales gas volume, which was estimated to be some 16 per cent. Dome said it had held discussions with

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[1] Energy Resources Conservation Board, 1982. Gas Processing Plant Expansions. Canadian Hunter Exploration Ltd., Sulpetro Limited, and Chevron Standard Limited. ERCB Report 82-G.

the other participants in the plant about reinjecting their ethane-plus liquids into the sales gas, although no commitments had been made by those parties to do so. Under these circumstances, Dome requested that the deep-cut facility be approved as applied for. In the event the participants decide to extract less ethane-plus product from the sales gas, a revised application would be made to the Board. Dome calculated that the incremental volumes of Wembley ethane would save enhanced oil recovery (EOR) operators $7 million (undiscounted) over the life of the project by substituting ethane for propane. Dome further said that if the Wembley ethane-plus liquids did not become available, there would be a shortage of ethane supply for miscible flood schemes.

Dome included an analysis of the costs and benefits to all parties effected by its project over the period 1986-2005. A summary of the results of this analysis is shown in Table 2 below.

Dome's analysis shows that the costs to the petrochemical industry and the Empress straddle plant operators are more than offset by the benefits to all other affected parties. The net benefit resulting over the project life was shown to be significant and positive under all appropriate discount rates.

Dome agreed that producers' proprietary rights should be protected, but the impact of upstreaming on the straddle plant operators and the petrochemical industry must also be considered.

4.3 Interveners' Views

Regarding the issue of incremental ethane, AGEC and Dow emphasized that Dome's calculation showed no incremental ethane would result from deep-cutting the sales gas portion of the Wembley plant throughput. Total suggested that Dome's estimate of incremental liquids was understated in the application because Total's nomination for plant capacity was not for sales gas only but included gas volumes that would be injected as part of its own cycling schemes in the Hythe and Doig pools (not yet applied for). Ocelot said that incremental volumes of ethane would also be recovered by deep-cutting the sales gas portion of the plant throughput because ethane recovery at the proposed Wembley plant would be higher than at the Empress straddle plants.

Total stated that it had sufficient demand from its own miscible flood projects which in the foreseeable future could use all of its share of the ethane-plus liquids that would be produced at Wembley. It had also received offers from other operators to purchase any liquids in excess of its own requirements. AGEC and Dow questioned Dome's plans either to displace specification ethane which might go to the EOR market with Wembley ethane or to fractionate its ethane-plus mix to make the ethane component available to the petrochemical industry if the EOR market could not absorb all the Wembley production. AGEC and Dow asked Dome how it could expect to do either when the cost of ethane (unfractionated) produced at Wembley would be higher than the cost of producing specification ethane in the straddle plant system.

With respect to the cost of extracting ethane at Wembley, AGEC commented that the unit cost calculated by Dome was only marginally higher for deep-cutting only the cycle gas compared to deep-cutting the whole plant throughput and even the higher cost appeared to be competitive with ethane at other previously approved field plants.

AGEC and Dow stated that they did not oppose deep-cutting the portion of the gas that would be cycled because that would not have any immediate impact on the straddle plant system. They were, however, opposed to deep-cutting any of the sales gas volume. They noted that Dome's analysis showed that while deep-cutting the Wembley sales gas would not result in any benefit in terms of incremental ethane for the province, it would impose a cost on

TABLE 2 COST/BENEFIT ANALYSIS

Net Benefits (Costs)	Discount Rate 0 Per Cent	10 Per Cent	20 Per Cent
	millions of dollars		
Field Plant	125	64	35
Petrochemical Industry	(23)	(9)	(1)
Straddle Plants	(123)	(38)	(17)
EOR Operators	7	3	1
Gas Producers	31	(2)	(5)
Provincial Government	246	85	49
Federal Government	192	75	42
Total	455	178	104

the petrochemical industry. In closing argument, AGEC and Dow said their concerns were partially alleviated when they learned that Dome and possibly Petro-Canada would be reinjecting into the sales gas ethane-plus liquids equivalent to their respective share of the sales gas volume. To further reduce the impact on their interests, AGEC and Dow requested that the Board condition any approval to require that all of the ethane-plus liquids extracted from the sales gas be fully restored to the sales gas.

Petro-Canada stated its commitment to restore ethane-plus liquids to the sales gas leaving the Wembley plant equivalent to its share of the sales gas volume, some 2.5 per cent of the total. PanCanadian also stated that it was considering either reinjecting ethane-plus liquids or by-passing the turbo-expander with its share of the sales gas which would be about 35 per cent of the plant's sales gas.

Total suggested that the impact of the Wembley project on the straddle plant system and the petrochemical industry may have been overstated in Dome's application because the volume of sales gas going from the Wembley plant to Empress would be less than what Dome assumed, due to Total's proposed cycling schemes.

Total did not comment on whether it was prepared to reinject any of its share of ethane-plus liquids back into the sales gas.

Total, Sulpetro, and Chieftain all stated that producers have the right to extract liquids from their gas at field processing plants and that it is in the public interest to maintain that right.

4.4 Board's Views

The Board concludes that Dome's estimate of the incremental volume of ethane that would be recovered by the proposed Wembley plant is low. The Board does not agree with Dome's assumption of an 80 per cent recovery factor at Empress and notes Dome's statement that the average ethane recovery efficiency at the Empress plants would not be much higher than 70 per cent. Clearly, some incremental ethane would result from deep-cutting the sales gas at the Wembley plant because of the difference in ethane recovery efficiencies. The Board, therefore, does not agree with AGEC and Dow's statement that there would be no benefit gained by deep-cutting the sales gas. It also follows that reinjection of ethane-plus liquid into the sales gas at Wembley to allow its extraction at Empress would result in some decrease in the incremental volume of ethane because of the difference in recovery efficiencies. Notwithstanding the above, the Board notes that the most significant part of the incremental volume of ethane-plus would result from deep-cutting the cycle gas because the ethane-plus product recovered from that gas would otherwise not be recovered until the termination of the cycling project. Given the present need for ethane in EOR projects, the Board continues to believe the incremental recovery of ethane at this time would be in the public interest.

Regarding the present and future markets for the ethane-plus liquids, the Board agrees with Dome that the EOR demand for ethane appears to be developing more quickly than was originally thought and existing and approved sources would not be able to meet the demand. The Board's own forecast of ethane supply and demand shows a relatively close tracking of supply and demand at the present time, with demand moderately exceeding supply into the 1990s as miscible flood requirements increase. The Board notes the comments of Dome and Total that they intend to use their respective share of the ethane-plus liquid produced at Wembley in their own miscible flood schemes for at least part of the life of the Wembley project.

The Board accepts Dome's evidence that the ethane-plus produced at Wembley would be competitive in the market-place. The Board notes that the actual cost of ethane extraction at Wembley may vary somewhat from the $\$27.04/m^3$ calculated by Dome depending on the amount of ethane-plus liquid reinjected into the sales gas leaving the plant. The Board believes that the effect of this reinjection would not alter the cost of the liquids produced at Wembley so significantly as to affect the competitiveness of this supply compared to previously approved field plants.

The Board notes that under all discount rates the proposed project generates a significant net benefit. The Board accepts the general approach used by Dome to quantify the impact on the petrochemical industry, although it believes that some of the assumptions may not be appropriate. The Board believes that the ethane recovery efficiency at Dome's proposed field plant would be significantly higher than at Empress and upstreaming would result in incremental recovery of ethane. Also, the Board notes that this assumption would exaggerate the amount of ethane that would be lost to the straddle plant system due to the upstreaming and consequently the impact on the petrochemical industry. The Board also notes the statement by Total that the impact was overstated because there would be less Wembley sales gas going to Empress due to Total's gas needs for its cycling projects. In addition, Dome's analysis neglects

the foregone revenue by the petrochemical industry for sales to the export or miscible flood markets of surplus ethane recovered at Empress in the absence of the proposed deep-cut facility. The impact calculated by Dome only considered the increased feedstock cost to the petrochemical industry. The negative impacts noted above would be partially mitigated by the commitments of Dome and Petro-Canada to return the ethane-plus liquids extracted from almost 20 per cent of the sales gas volume back into the sales gas. The Board notes that PanCanadian was also considering similar treatment of its portion of the sales gas which represents about 35 per cent of the total sales gas. Although the Board has not undertaken a rigorous calculation of how the above-mentioned factors would adjust the magnitude of the impact on the straddle plant system and petrochemical industry, it notes the factors would be offsetting and believes the net result would not be sufficient to alter the net benefit substantially. The Board also notes that the analysis was prepared assuming full taxation for all parties. Considering that some companies may not be subject to taxation throughout some of the study period, the impact on government would be less than shown.

The Board has reviewed the cost/benefit analysis submitted by Dome and believes that it is directionally correct although the Board would have used some assumptions differently than Dome. From its analysis of the information supplied by Dome, the Board believes that there would be no overall public benefit associated with reinjecting liquids into the Wembley sales gas although this would reduce the impact on the petrochemical industry.

With respect to the matter of the proprietary rights of gas producers, the Board maintains that the producers' right to extract liquids from their gas streams is in the general public interest, although it is only one of the many factors that should be considered in assessing the effect of upstreaming.

With respect to the upgrading of resources in Alberta, the Board notes that to the extent that incremental volumes of ethane would result from the proposed deep-cut facility, upgrading would occur. The conservation benefits of the whole project are obvious as discussed previously in this report and would not be reduced by the proposed deep-cut facility. The Board believes that the proposed deep-cut facility would have essentially no environmental impact.

5 APPLICATIONS 841010 THROUGH 841016 — THE PIPELINE APPLICATIONS

5.1 Description of the Applications

Dome applied pursuant to Part 4 of the Pipeline Act for permits to construct pipelines to gather sour gas from wells and batteries in the La Glace-Wembley area for processing at its proposed Wembley gas processing plant, to return residue gas for its proposed gas cycling scheme, and to distribute fuel gas to field facilities.

Details of the pipeline applications are set out below.

5.1.1 Sour Production — South Lateral

Application 841010 is for a permit to construct approximately 18.72 km of 88.9-, 168.3-, and 219.1-millimetre (mm) outside diameter pipeline and related facilities to transport sour natural gas with a maximum H_2S content of 28.2 mol/kmol from wells in Lsd 7-1-73-8 W6M and Lsd 7-15-73-8 W6M, and from existing batteries at Lsd 11-36-72-8 W6M and Lsd 14-3-73-8 W6M to the proposed gas plant at Lsd 6-19-73-8 W6M.

5.1.2 Sour Production — North Lateral

Application 841011 is for a permit to construct approximately 23.67 km of 88.9-, 114.3-, 168.3-, 219.1-, and 273.1-mm outside diameter pipeline and related facilities to transport sour natural gas with a maximum H_2S content of 5.0 mol/kmol from wells in Lsd 14-11-75-9 W6M, Lsd 6-35-74-9 W6M, Lsd 10-12-74-9 W6M (10-12), Lsd 10-31-73-8 W6M, and Lsd 6-29-73-8 W6M to the proposed gas plant.

5.1.3 Fuel Gas — North Lateral

Application 841012 is for a permit to construct approximately 28.95 km of 88.9-mm outside diameter pipeline and related facilities to transport fuel gas from the proposed gas plant to all of the wells in Applications 841011, 841014, and 841016.

5.1.4 Fuel Gas — South Lateral

Application 841013 is for a permit to construct approximately 21.63 km of 88.9-mm outside diameter pipeline and related facilities to transport fuel gas from the proposed gas plant to all of the wells in Applications 841010 and 841015.

5.1.5 Sour Gas Injection

Application 841014 is for a permit to construct approximately 7.37 km of 88.9-mm outside diameter pipeline and related facilities to transport sour natural

gas with a maximum H_2S content of 200.0 mol/kmol from the proposed gas plant to a well located in Lsd 14-19-73-8 W6M (14-19) and to proposed wells in Lsd 6-32-73-8 W6M (6-32) and Lsd 9-6-74-8 W6M (9-6) for purposes of gas injection.

5.1.6 Sweet Gas Injection — South Lateral

Application 841015 is for a permit to construct approximately 18.71 km of 88.9-and 114.3-mm outside diameter pipeline and related facilities to transport sweet natural gas from the proposed gas plant to wells located in Lsd 6-22-73-8 W6M, Lsd 6-16-73-8 W6M, Lsd 6-11-73-8 W6M, and Lsd 14-31-72-7 W6M for purposes of gas injection.

5.1.7 Sweet Gas Injection — North Lateral

Application 841016 is for a permit to construct approximately 26.79 km of 88.9-, 114.3-, and 168.3-mm outside diameter pipeline and related facilities to transport sweet natural gas from the proposed gas plant to wells located in Lsd 6-28-73-8 W6M, Lsd 15-7-74-8 W6M, Lsd 6-13-74-9 W6M, Lsd 6-14-74-9 W6M, Lsd 10-22-74-9 W6M, Lsd 11-26-74-9 W6M, Lsd 6-2-75-9 W6M, and Lsd 6-1-75-9 W6M for purposes of gas injection.

5.2 Issues Regarding the Pipelines

The Board considers the pipeline-related issues to be:

- the purpose and necessity of the proposed pipelines, and
- technical and environmental considerations.

5.3 Applicant's Views

Dome stated that the pipelines would be needed to implement its proposed cycling scheme by gathering gas from production wells for processing at its applied-for gas plant and returning sweet residue and diluted acid gas to injection wells, and to transport fuel gas to operate well-site heaters and other facilities. Dome noted that its south production lateral would also gather solution gas that is currently being flared at the existing PanCanadian 11-36-72-8 W6M (11-36) and Total 14-3-73-8 W6M (14-3) batteries.

Dome indicated that it planned to drill two additional production wells, two more sour gas injection wells, and one sweet gas injection well during the summer of 1985, to be located at Lsd 13-24-74-9 W6M and Lsd 6-21-73-8 W6M, 6-32 and 9-6, and Lsd 7-20-73-8 W6M, respectively. It advised that all of these proposed wells would be completed and tested prior to the start of pipeline construction, scheduled for mid October 1985. Dome stated that the timing of drilling the wells would allow testing the proposed 6-32 and 9-6 sour gas injection wells prior to pipeline construction, thereby confirming the need to construct the sour gas injection pipeline past the existing 14-19 sour gas injection well.

Dome stated its pipelines would be designed and installed in accordance with the Canadian Standard Association standard Z184-M1983[2] Gas Pipeline Systems.

Dome stated that its proposed north and south sour gas production laterals would be classified as Level 1 and Level 2 sour gas facilities, respectively, in accordance with ERCB Interim Directive ID 81-3[3]. Dome noted that the acid gas to be transported via the injection pipeline would be dehydrated and diluted at the plant with sweet residue gas to approximately 200 mol/kmol of H_2S and diluted further at the wellhead with sweet gas from the gas pipeline to approximately 100 mol/kmol of H_2S. The addition of sweet gas is needed to ensure sufficient reservoir voidage replacement. The H_2S content in the sour gas that would be produced at nearby wells may increase to approximately 40 or 45 mol/kmol of H_2S over the life of the cycling scheme because of localized injection of acid gas into the reservoir.

Dome said that its proposed production lines were, from a materials standpoint, designed to accommodate higher concentrations of H_2S, and that dilution would occur during production as a result of lower H_2S gas production from wells farther north. Additional emergency shut-down valves could be located along the north line to maintain its Level 1 classification.

Dome stated that it had revised its proposed pipeline routing in the vicinity of the PanCanadian 11-36 battery to parallel an existing Peace Pipe Line pipeline to accommodate landowners' concerns. With respect to the remainder of its proposed pipeline system, Dome said it was not aware of any landowner objections to the routing proposed.

In response to questions from Alberta Environment, Dome confirmed that the pipeline routing to the north of La Glace Lake was on the north side of the

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[2] Canadian Standards Association, 1983. Gas Pipeline Systems, Pipeline Systems and Materials. Standard Z184-M1983. Rexdale, Ontario.

[3] Energy Resources Conservation Board, 1981. Minimum Distance Requirements Separating New Sour Gas Facilities From Residential and Other Developments. Interim Directive ID 81-3, Calgary, Alberta.

10-12 well-site access road and not in the shoreline vegetation.

Dome advised that it planned to start pipeline construction in October to minimize interference with local harvesting. It verified that construction in the vicinity of the duck bait station on the north shore of La Glace Lake would not begin until after 15 October 1985, normally the last day of operation of the station.

With respect to potential impacts to soils that may result during wet weather, Dome stated that any decisions to stop construction would be made by its environmental engineers and field construction supervisors and they would take into account the opinions of the landowners affected as well as those of the district agriculturist. Dome stated it believed that mid October construction would result in less landowner and soil-related impact, furthermore, it would avoid increased winter construction costs.

5.4 Interveners' Views

Total supported Dome's applications and stated that the proposed pipelines would gather solution gas currently being flared at its 14-3 battery.

The Farm Rights groups did not oppose the pipeline applications because they supported reduced flaring of solution gas in the area.

5.5 Board's Views

The Board agrees that the proposed pipelines would be needed to implement Dome's gas cycling scheme and to gather the solution gas presently being flared at the PanCanadian 11-36 and Total 14-3 batteries. Additionally, it believes that the sour gas injection pipeline to the proposed 6-32 and 9-6 wells would be required should Dome's testing program verify that these wells are suitable injectors.

The Board has reviewed the proposed pipeline design and based on the information submitted, it is satisfied the design of the pipelines and related facilities proposed by Dome would meet the requirements of CSA Z184-M1983 and the Pipeline Act and Regulations.

The Board has reviewed the potential H_2S release volumes that would result if natural gas containing 40 to 45 mol/kmol of H_2S were transported in the north production lateral and believes that the valve spacing, currently proposed by Dome, would classify the lateral as a Level 2 sour gas facility. However, the H_2S content could be reduced by lower H_2S gas from potential wells in the north end of the field. The Board notes that the segment of the north production lateral in question would parallel the proposed Level 2 sour gas injection pipeline which would require Level 2 separation distances.

The Board observes that no landowners objected to the proposed pipeline routing and is satisfied that the routes proposed by the applicant are appropriate.

The Board has reviewed Dome's proposed construction timing and believes that the construction should not interfere significantly with harvest operations. Regarding construction and potential soil impacts during possible wet conditions, the Board accepts Dome's commitment that the views of the potentially affected landowners would be considered. Additionally, it notes that ERCB pipeline inspectors would be available for affected landowners to contact should any concerns arise. They can be reached at the Board's Grande Prairie Area Office (538-5138).

6 BOARD FINDINGS

6.1 Cycling Scheme

The Board is satisfied that the proposed cycling scheme at a VRR of 0.75 provides a satisfactory level of hydrocarbon conservation.

6.2 Gas Plant

The Board believes the plant is of adequate design and size to process known as well as other potential gas supplies in the area and that the plant meets provincial environment standards.

6.3 Ethane Extraction

While the Board recognizes that the proposed deep-cut facility would result in some impact on the Empress straddle plants and would affect the petrochemical industry to a certain extent, the Board believes that benefits to other parties and the overall benefit to the province justify approval. Incremental recovery of ethane would result largely from deep-cutting the gas for the proposed cycling operations. The Board believes that a cost/benefit analysis of deep-cutting the sales gas volumes alone would also show a small net benefit to the province, taking into account the difference in recovery efficiencies between the Wembley plant and the Empress straddle plants. While the Board recognizes an overall net benefit, it is very concerned about the progressive negative impact this approval would have on the petrochemical industry. The Board is generally aware of the present situation of the Alberta petrochemical industry and believes it is largely due to global factors; however, this is aggravated by the cumulative effect that upstreaming has on its feedstock supply. The Board is of the view, however, that recent changes

in government policy affecting the price of gas supplied to the petrochemical industry represents a benefit significantly larger than the cumulative effect of upstreaming to date. Therefore, although the Board still sees upstreaming of the straddle plant system as an important factor in terms of future feedstock supply for the petrochemical industry, it does not see it as being as critical in terms of the industry's viability at the present time.

6.4 The Pipeline Applications

The Board agrees that the proposed gathering system will provide for conservation of gas now flared at a number of facilities. The fuel gas and injection lines are necessary components of the proposed scheme. The Board believes that technical design and environmental matters have been adequately addressed by the applicant.

7 DECISION

Having considered the evidence of the applicant and the interveners, the Board is prepared to grant the applications for the cycling scheme, the processing plant and the resulting ethane extraction, and the pipelines proposed to provide fuel, to gather, and inject gas as required by the project.

The Board will issue its approval for the proposed plant and pipelines, subject to receipt of approval from the Minister of Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 28 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman, P.Eng.
Board Member

F. L. Mink, P.Eng.
Acting Board Member

TABLE 3 VALHALLA-WEMBLEY HALFWAY B GAS CAP WORKING INTEREST OWNERS
Dome Petroleum Limited (Dome)
Chieftain Development Co. Ltd. (Chieftain)
Esso Resources Canada Limited (Esso)
Ocelot Industries Ltd. (Ocelot)
PanCanadian Petroleum Limited (PanCanadian)
Petro-Canada Inc. (Petro-Canada)
Sulpetro Limited (Sulpetro)
Texaco Canada Resources Ltd. (Texaco)
Total Petroleum Canada Ltd. (Total)

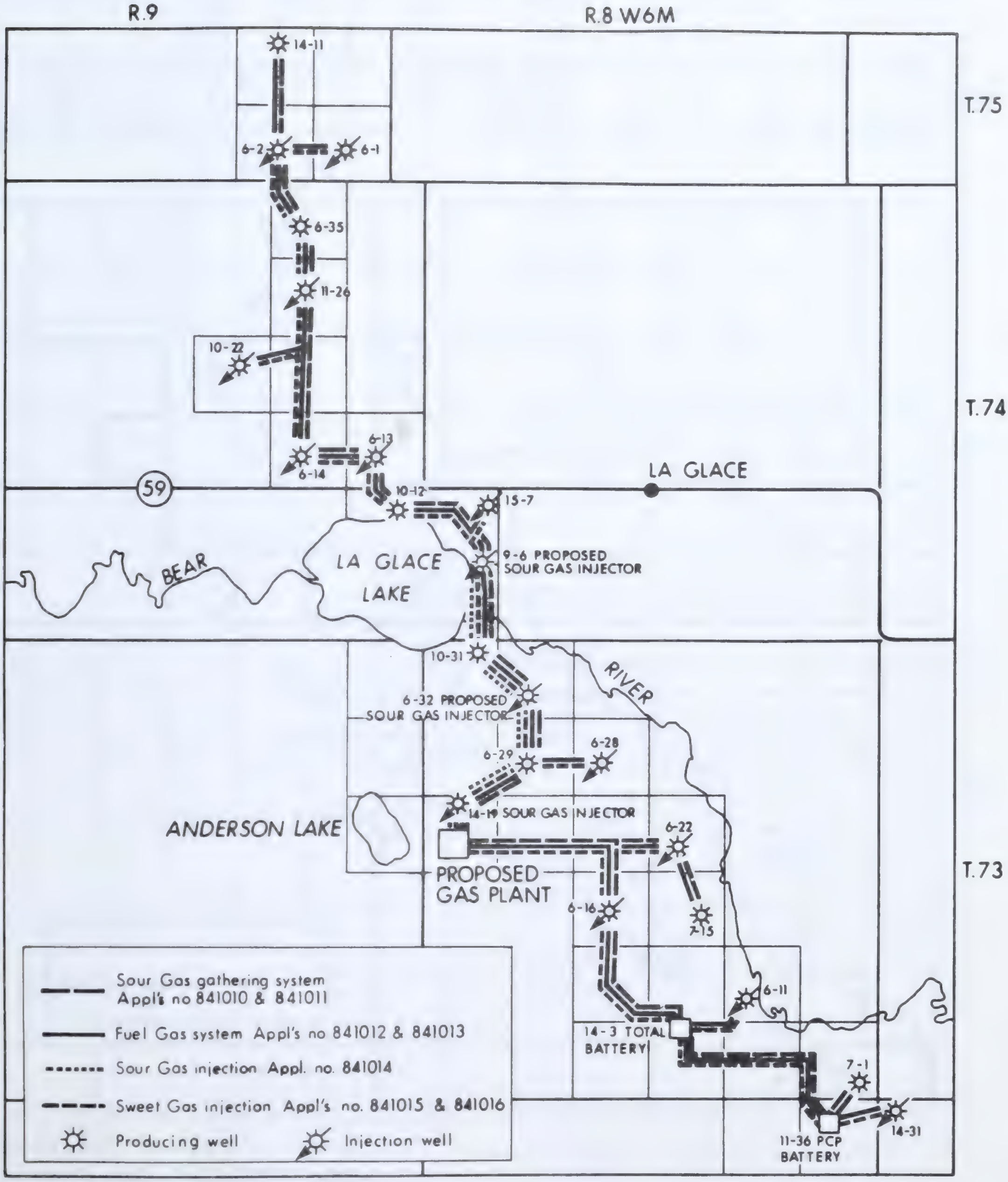

FIGURE 1
DOME PETROLEUM LIMITED
APPLICATIONS NO. 840607, 840816 & 841010 to 841016
LA GLACE - WEMBLEY AREA

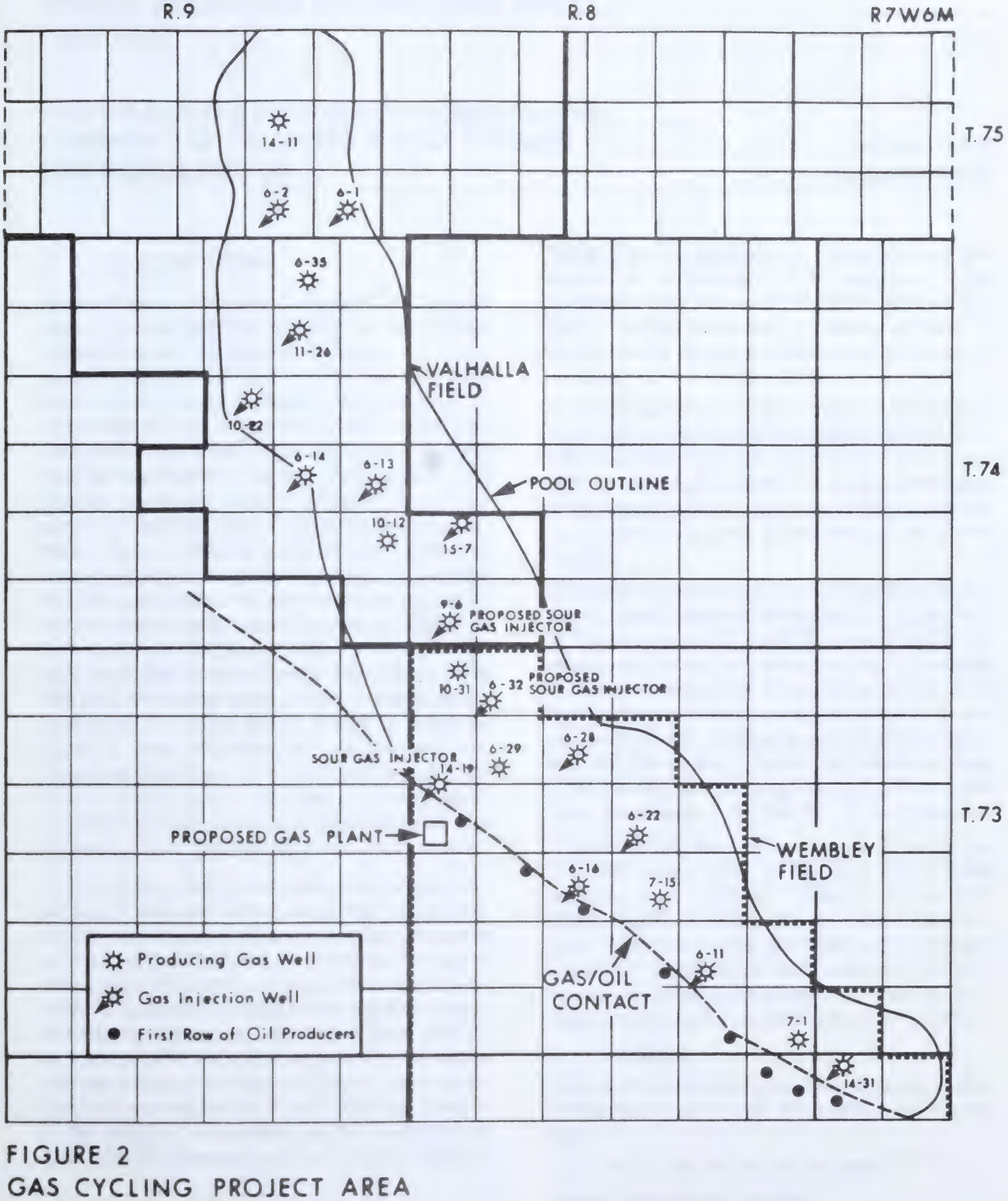

FIGURE 2
GAS CYCLING PROJECT AREA
APPLICATION NO. 840607

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

AMOCO CANADA PETROLEUM COMPANY LTD. COMMERCIAL OIL SANDS PROJECT (PHASE 1) LINDBERGH SECTOR

Decision D 85-15
Application 840227

1 INTRODUCTION

Amoco Canada Petroleum Company Ltd. (Amoco) applied, in accordance with section 10 of the Oil Sands Conservation Act, for approval of Phase 1 of a three-phase commercial oil sands project (the Elk Point Project) in the Lindbergh Sector of the Cold Lake Oil Sands Deposits. The project offsets other nearby projects operated by Dome Petroleum Limited (Dome), PanCanadian Petroleum Limited (PanCanadian), and Westmin Resources Limited (Westmin) in an area previously described as the Lindbergh heavy oil field. Phase 1 would consist of a 13-well cyclic steam and steam-flood stimulation project developed on 2-hectare (ha) well spacing and a 640 cubic metres per day (m^3/d) bitumen cleaning plant (central processing facility)[1] in Area A as shown on Figure 1. Phase 1 would also include the drilling of approximately 160 wells on 16-ha (one legal subdivision) spacing with a southeast quarter legal subdivision target area in Area B as shown on Figure 1. These wells would be cold produced for a limited period of time. Up to 20 of the Area B wells would be subjected to cyclic stimulation, using steam and carbon dioxide (CO_2), on a temporary basis. The requested term of approval for Phase 1 is 5 years.

On 24 February 1984, it was announced by the governments of Canada and Alberta, along with Amoco, that the Elk Point Project would proceed as final agreement had been reached respecting the royalty and tax regime to be applied to the project. Subsequently, Amoco submitted its application for Phase 1 of the Elk Point Project to the Energy Resources Conservation Board (ERCB) on 5 March 1984. As a result of review by the ERCB and other concerned government agencies, additional information was requested on 5 April 1984. After review of this additional information and the completion of Amoco's public awareness program in August 1984, the ERCB judged the application to be complete and proceeded with advertisement of the application in mid September 1984. This notice resulted in several objections to the application and, in a subsequent notice, a public hearing of the application was scheduled to commence on 4 December 1984.

In view of concerns expressed by a number of interveners respecting the scheduled hearing commencement date, a prehearing meeting was conducted on 27 November 1984 by the Board to resolve the matter. The hearing of the Amoco application was subsequently rescheduled three times in an effort to accommodate all parties involved.

Interventions expressing concern and qualified opposition to Amoco's application were filed by Mr. and Mrs. D. Kadutski and Mr. M. Kadutski, occupants and owner, respectively, of the north half of section 29, township 55, range 6, west of the 4th meridian; the Elk Point Surface Rights Association; and Ms. L. Keith, an area rural resident. Interventions in support of the application were filed by Ms. J. Darling, on behalf of a group of Elk Point/Lindbergh area residents, the Town of Elk Point, the County of St. Paul No. 19, and Westmin.

A public hearing was held on 8, 9, 12, 15 to 18, and 21 to 23 January 1985 in Elk Point before Board members, G. J. DeSorcy, P.Eng., L. A. Bellows, P.Eng., and N. A. Strom, P.Eng. A view of the proposed project site and the immediate surrounding area was taken by the Board and representatives of the applicant and interveners in the afternoon of 9 January 1985. Those who appeared at the hearing are shown in Table 1.

2 ISSUES

The Board believes that the numerous issues raised during the hearing fall into the five general areas outlined below:

- the need for the project and the phasing of it
- broad environmental concerns
- project location and access
- reserves, recovery efficiency, and other technical concerns
- economic, social, and other concerns.

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[1] The central processing facility includes bitumen treating and storage facilities, water processing facilities, truck weigh scales, storage yard, and offices.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Amoco Canada Petroleum Company Ltd. (Amoco) J. N. Havelock	M. Trethart, P.Eng. R. L. Findlay R. W. Smook, P.Eng. B. Goruk, P.Eng. G. Grant, P.Ag. H. Zuorro R. Banek E. H. Bolstad, P.Eng., of Bolstad Engineering Associates Ltd. P. Vetro, P.Eng., of Western Research
Mr. and Mrs. D. Kadutski and Mr. M. Kadutski (the Kadutskis) B. K. O'Ferrall	D. Kadutski C. Kadutski M. Kadutski R. Berrien A. Larsen
Elk Point Surface Rights Association (EPSRA) P. T. Johnston	A. Bugej R. Danyluk D. Torok
Ms. L. Keith	L. Keith
Group of Elk Point-Lindbergh Area Residents J. Darling	J. Darling
Town of Elk Point (the Town) L. P. Vincent	L. P. Vincent E. Buck
County of St. Paul No. 19 (the County) R. Bouchard	R. Bouchard R. Smith
Westmin Resources Limited (Westmin) D. Repka	B. Mann
Energy Resources Conservation Board staff M. J. Bruni R. G. Evans, P.Eng. J. R. Nichol, P.Eng. B. P. Fenlon, P.Eng. R. Feick I. Weleschuk, P.Ag.	

3 THE NEED FOR THE PROJECT AND THE PHASING CONCEPT

Amoco said that the production of crude bitumen from Alberta's large oil sands reserves offers the most expedient solution to the need for the replacement of rapidly declining conventional oil reserves. Amoco proposed to commence Phase 1 of a three-phase commercial oil sands project with a maximum crude bitumen production of 640 m^3/d during Phase 1 increasing to 3630 m^3/d during Phases 2 and 3.

In addressing the need for another cleaning plant in the Elk Point area, as proposed in Phase 1, Amoco stated that several of the existing central processing facilities in the area could not accommodate Amoco production as they are already approaching maximum processing capacity. By owning and operating its own facility,

Amoco would not be subject to the priorities imposed by another facility operator when processing production from several companies. Amoco indicated that its proposed central processing facility was sized to handle Phase 1 production only and that it would not be processing production from any other operators in the area.

Amoco also indicated that Phase 1 is a necessary step in that its purpose is to confirm the thermal recovery method and operational strategies that would be used in Phases 2 and 3. Although Amoco expected that sufficient data on which to base its decision to proceed to Phases 2 and 3 would be available within 2 years of the start of Phase 1, it requested a 5-year term of approval to allow for full evaluation of the 13-well thermal project and to provide for contingency time in the event of operational problems.

Despite the evaluative nature of Phase 1, Amoco viewed it as "commercial" in accordance with the fiscal arrangements negotiated with the federal and provincial governments and sought a commercial approval from the ERCB. Should Phase 1 prove successful, Amoco stated that it would make a second application to the ERCB for Phases 2 and 3 in which the full details and various impacts of those phases would be addressed.

Although the need for the commercial oil sands project itself was not questioned, the Kadutskis and EPSRA expressed concern over the potential redundancy and possibly avoidable environmental impacts of oil industry-related facilities, such as the Phase 1 central processing facility, in the Elk Point area. They suggested that Amoco first carefully investigate the potential use of existing area central processing facilities, such as Westmin's and Dome's, before constructing yet another such facility. Concern was also expressed over the potential use of Amoco's proposed central processing facility by other operators, thereby aggravating the problem of excessive numbers of tank trucks accessing Amoco's facility site.

Ms. Darling and the Town agreed with the need for the project in alluding to the positive benefits that would be gained by the Elk Point community.

The Board is in agreement with Amoco with respect to the need for a commercial oil sands project. Also, while the Board recognizes the advantages in developing such a project in phases as Amoco has proposed, it wishes to stress that it is only considering Phase 1 of the project at this time and will require further applications for subsequent phases. Of particular importance is that in such subsequent applications it would be necessary to fully address technical, environmental, and socio-economic issues.

Although the Board views aspects of Phase 1 to be in part experimental in nature, it nevertheless is prepared to recognize Phase 1 as the preliminary phase of a commercial project. The Board, in taking this view, defers comment on the commercial viability of the proposal until sufficient technical, environmental, and socio-economic impact data are available.

The Board believes that the 13-well thermal project, the drilling of additional wells, and the steam/CO_2 stimulation of a number of those wells are all appropriate first steps in the overall project, and thus there is a need for those operations if the overall project is to become a reality.

Respecting the possibilities of optimizing the number, size, and distribution of central processing facilities in the Lindbergh development area, the Board understands that the option of fewer larger facilities would have certain environmental advantages, particularly respecting process emission control. On the other hand, transportation impacts could be increased if pipeline transportation limits for delivery of raw products are exceeded. At this point in time there is no easy way to establish from an engineering or operating viewpoint whether the overall environmental impacts would be decreased or increased through greater processing facility centralization. Considering the comparatively small size of the Amoco Phase 1 facility and the fact that a future expansion would have to be fully addressed on its own technical and environmental merits in a future application, the Board does not judge the Amoco Phase 1 facility to be redundant or inappropriate.

4 BROAD ENVIRONMENTAL CONCERNS

A number of environmental concerns were raised at the hearing which pertain to the impacts of oil industry-related activity on residents and land in the broad Elk Point area. These concerns are discussed in this section of the report as they relate to the broad Lindbergh Field area rather than a single landowner or occupant.

4.1 Noise

EPSRA expressed concern that increasing incidents of hearing loss in farmers in the area might be the result of increases in ambient noise levels. It said that these increased levels are, in part, due to the cumulative effect of oil industry-related activity. EPSRA further stated that the noise guidelines set out in ERCB Interim Directive ID 80-2 are not applicable to areas, such as the Lindbergh Field, where high density well spacing is necessary for recovery of crude bitumen. It recommended that ambient noise level increases should not be allowed to exceed 5 dBA Leq above the dominant ambient noise level that existed in the area prior to the intrusive noise

occurring. EPSRA said that this guideline should be applied to continuous noise sources such as central processing facilities, while short-term noise sources such as well drilling operations would be exempt.

EPSRA did not address the applicability of its recommended guideline to noise from truck traffic as it was uncertain as to whether this source could be categorized as short term. However, EPSRA did recommend that the use of engine retarder brakes (also known as "jake brakes" and characterized by their staccato popping sound when engaged) which are found on many oil field tank trucks be prohibited near residences. It also recommended that all oil field-related activities which cause noise, such as construction and well servicing operations, but with the exception of well drilling operations, should be prohibited during night-time hours. Finally, EPSRA called for a noise impact assessment of the general area with the results being subject to its recommended noise guideline.

The Kadutskis were in support of the broad concerns expressed by EPSRA with respect to noise. Ms. Keith also indicated concern in this regard.

Amoco, for its part, acknowledged that it would be creating some noise in its Phase 1 operations from sources such as truck traffic, internal combustion engines on pumpjacks, processing facility equipment noise, and construction activity.

Amoco stated that it had completed a noise impact assessment study of the D. Kadutski residence and planned a number of noise control measures for its Phase 1 operations. These include the electrification of the plant site and the 13-well thermal project and the reduction of noise-causing truck traffic by the installation of a fresh water supply pipeline very shortly, and the possibility of a clean oil products pipeline when there is sufficient confidence that sustained bitumen production can be achieved. The latter may take a couple of years to prove up. As a result of these measures, Amoco expressed the view that in the longer term, noise from its operations would have relatively low, tolerable impact on residences in the general area. Amoco indicated that installation of pipelines to replace raw products hauling by tank truck would have to await completion of a significant portion of the Phase 1 operation period. It suggested it would not be less than 2 years before that is realized.

The Board appreciates the potential for disruptive noise impacts from oil field construction activities and well servicing operations, as well as the intrusive nature of noise from engine retarder brakes on large trucks. It believes that such impacts could be reduced by limiting construction activities and well servicing operations to daylight hours only, excepting the possibility of well servicing on an emergency basis. It also believes that use of engine retarder brakes could be better controlled to the extent that is practical through directives issued to trucking contractors by their oil company employers. On the preceding points, and with respect to noise impacts on the general area, the Board accepts Amoco's commitments to restrict most operations to daylight hours and to restrict the use of engine retarder brakes by trucking contractors in its employ. It does so, however, on the understanding that noise complaints would be immediately investigated by Amoco and that appropriate mitigative action would be taken. With regard to hearing loss experienced by farmers in the area, the Board does not believe that the noise levels would be such that this type of effect would occur.

It is clear that a system of oil field production gathering pipelines to move raw bitumen emulsion to the central processing facilities and also, to the extent feasible, to move fresh processed water to steam generator sites, would considerably reduce field tank trucking. The effect would be to significantly reduce local impacts including traffic congestion and noise caused by trucking activities. The Board accepts that Amoco will not be in a position to establish the most appropriate sizing and routing of such an oil field pipeline system until it has established a reasonable history of production operating experience especially for steam-stimulated wells. The Board concludes that, until the oil field production gathering pipelines are installed, the only practical mitigation measure is a system of traffic route control and truck operating guidelines, more or less as proposed by Amoco.

Respecting clean bitumen (oil) shipping, the Board similarly concludes that replacement of product tank trucks by a product pipeline tie-in to the central processing facility would eliminate that traffic impact. From a technical viewpoint, the most desirable time to proceed with design and installation of the bitumen sales pipelines would be perhaps some 2 or 3 years after Phase 1 start-up. On the other hand, there may be sufficient field performance information shortly after start-up to permit satisfactory "scoping" of the facility. The Board believes that the products pipeline should be installed as soon as possible and will direct Amoco to report on the feasibility of a products pipeline 6 months after the start-up of the central processing facility. In the meantime, other mitigative measures along the lines proposed by Amoco to limit adverse impacts from sales product tank truck traffic would have to be relied upon.

As stated in other reports, the Board recognizes that there are concerns with the existing noise guidelines in ERCB Interim Directive ID 80-2. These guidelines, as well as the need for noise abatement regulations, are currently under review by the ERCB in consultation with Alberta Environment.

4.2 Traffic

A number of interveners cited several problems, in addition to noise, attributed to oil industry-related traffic.

EPSRA expressed serious concern that the increasing number of heavy trucks on county roads are causing rapid deterioration of road surfaces. It also expressed concern, as did the Kadutskis and Ms. Keith, over the lack of road safety on the part of a small percentage of oil industry personnel. Typical concerns were the exceeding of posted speed limits, failure to yield or stop, failure to share the roadway with other vehicles, and particularly, failure to reduce speeds on roads adjacent to residences with children.

Concern was also raised over the routing of traffic between the proposed Amoco plant site, the isolated production wells, and the point of sales. Similar concern was expressed in relation to several other oil sands operators in the Lindbergh Field area and the need for co-ordination of traffic routes among all operators.

Questions were also raised as to whether the oil industry should provide additional money for road construction and maintenance, as it appeared to be the major user of certain county roads. The interveners also identified the need for school bus loading zones with reduced speed limits as well as a means of identification of oil industry-related vehicles.

Amoco, in responding to concerns over the numbers and types of vehicle traffic using county roads, provided estimates of the traffic its project would generate during both the construction and drilling phases and the subsequent operations phase. Amoco also indicated that it, along with other area operators, was working with Alberta Transportation in determining and co-ordinating major truck routes in the Lindbergh Field area. Amoco had also recognized the concerns respecting road safety and had issued a memorandum to all of its trucking and service firms outlining traffic guidelines to be observed. These guidelines address many of the interveners' concerns including speed limits, prohibition of the use of engine retarder brakes, use of major truck routes, and road courtesy. Amoco also noted that all its company vehicles are numbered for easy identification and it would be prepared to pursue such an identification program with the subtrades it contracts.

The Town and the County indicated each had made submissions with respect to major traffic routes and road upgrading priorities to the Heavy Oil and Oil Sands Review Committee. The County also outlined a number of designated truck routes for which it was trying to obtain resource road grants from the provincial government to facilitate the necessary upgrading.

The Board is very cognizant of the concerns of the interveners with respect to increasing oil industry-related traffic in the Lindbergh Field area and, indeed, the entire northeast section of central Alberta. It endorses the efforts of oil companies, such as those committed to by Amoco, to minimize traffic impacts through self-imposed traffic safety guidelines and participation in meetings with other operators, landowners, county and municipal governments, and Alberta Transportation.

Respecting the traffic impacts in the general area of the Amoco Phase 1 project, the Board is satisfied those can be held to an acceptable level provided that Amoco adheres to all of the undertakings given at the hearing. To ensure that this is done, the Board would require Amoco to submit an initial report, and ongoing ones as appropriate, detailing efforts to minimize traffic impacts on the area.

4.3 Dust

The Kadutskis and EPSRA expressed concern with the large amount of dust raised by oil industry-related vehicles. They noted that reduced visibility because of dust on county roads represented a safety hazard. Excessive dust also presented a maintenance problem in that it covered automobiles, houses, and crops.

Amoco stated that it had made its produced oily sand available to the county for use as a dust suppressant on roads and was prepared to apply such produced sand to the roads fronting properties of those landowners who requested such a service.

The Board agrees with the interveners that excessive dust raised by traffic on county roads is a potential safety hazard. The Board believes that the proper application of produced oily sand is an acceptable means of dust control and has further comments respecting the matter of produced sand disposal in section 4.6 of this report.

4.4 Atmospheric Emissions and Monitoring

EPSRA and Ms. Keith expressed serious concern that the cumulative effects of emissions from all wells and processing facilities in the Elk Point area are unknown. They fear that these cumulative effects are lowering the air quality and present a serious health hazard. Of particular concern was the venting of any gases containing hydrogen sulphide (H_2S). Both EPSRA and Ms. Keith took the position that all produced gases not used for fuel purposes should be incinerated. Ms. Keith also said that the present provincial air quality standards are inadequate with respect to low level exposure to H_2S.

The interveners called for continuous air quality monitoring throughout the duration of Amoco's project with the monitoring results being made available to the local public. As a result of incidents related to Amoco's air

monitoring trailer located in D. Kadutski's yard in December 1984, the Kadutskis, EPSRA, and Ms. Keith all expressed some doubt as to the reliability of monitoring equipment. (The incidents are being investigated and will be reported to residents of the area in a separate document.)

Amoco indicated that all produced gases, with the exception of some gases from primary production wells, would be incinerated using flare stacks with automatic ignition devices. Amoco did note that, in the case of isolated primary production wells, the produced gas volumes might be so low as to require supplementary fuel in order to flare them. In such cases, produced gas would be vented to atmosphere provided it did not contain any H_2S. Amoco stated that emissions from all of its operations would be maintained within the provincial air quality standards.

The Board notes and is satisfied with Amoco's commitments to gather and flare all produced gases from the central processing facility and the 13-well cyclic steam project, to flare all gases produced at isolated single cyclic steam test wells, to flare where possible all gases produced at primary production wells, and to flare all gases which contain H_2S.

The Board agrees with certain interveners that the cumulative effects of emissions from all sources in the area are unknown. It believes the strategic placement of continuous air monitoring trailers throughout the area would provide such information. It notes Amoco's commitment to place such a trailer adjacent to the central processing facility in the north half of section 28-55-6 W4M for the first year of operations. It encourages Amoco and other area operators to give consideration to extending the term of continuous air monitoring in view of the potential for adverse cumulative effects from oil industry-related emissions. Indeed, depending on the results of monitoring and the development of operations in the area, the Board, in conjunction with Alberta Environment, will require a suitable amount of ongoing long-term monitoring.

4.5 Water Source and Usage

Both the Kadutskis and EPSRA called for the prohibition of the use of groundwater for any of Amoco's proposed activities with the exception of the domestic water needs for a field office. Their concern was based on the contention that groundwater supplies were limited in the Elk Point area and such water supplies were an absolute necessity to carry on agricultural activity. EPSRA also expressed fears that such groundwater supplies were subject to contamination by oil industry-related activity and called for the annual testing of domestic water wells surrounding Amoco's project with the results being made available to concerned residents.

Amoco indicated it would restrict its use of groundwater to supplying its office needs and that water for the purpose of supplying steam boilers or other oil field operations would be obtained from the North Saskatchewan River. Amoco also committed to the annual testing of approximately 15 domestic water wells in the area of its proposed project and to making the results available to the residents concerned.

The Board is satisfied with the commitments of Amoco with respect to restricting groundwater usage and its domestic water well testing program.

4.6 Waste Products Disposal

EPSRA expressed general concern that every precaution be taken in the operation of salt water disposal wells to prevent contamination of potable groundwater aquifers. In response, Amoco indicated it had not encountered problems with the operation of salt water disposal wells in the past and that it intended to keep injection pressures below fracture pressure to prevent interzonal communication.

The Board notes that all water disposal wells must comply with ERCB requirements that are designed to ensure complete protection of groundwater aquifers. It notes also that a further site-specific application for a disposal well is required and that the details will be fully reviewed at that time.

EPSRA objected to the use of sand containing oily wastes, which is often produced in conjunction with crude bitumen, as a dust suppressant on lease and county roads. It was primarily concerned that improper application of such sand would allow contaminants in the sand to run off the roads and eventually into groundwater supplies.

The Board considers the use of produced oily sand as a dust suppressant on roads to be an acceptable practice, providing reasonable guidelines concerning oil characteristics are known and methods of application are sound. The ERCB has devised preliminary guidelines in this regard but believes these should be reviewed by Alberta Transportation and Alberta Environment to ensure suitability.

The Board notes that groups such as the Sask-Alta Heavy Oil Waste Management Co-Op are studying alternative methods of oily sand disposal. Should an acceptable alternative disposal method be found, it is likely that ERCB policy concerning this issue would be revised.

The Town indicated its concern over the lack of sanitary landfill sites for rural ratepayers and the suitability of such sites for the disposal of wastes, such as sludge from sump pits, by local oil field service companies. It called for the development of guidelines and regulations

concerning the disposal of service company wastes, if they do not already exist, and that suitable disposal facilities be provided locally.

The Board suggests that the matters of an adequate number of sanitary landfill sites and regulations concerning proper disposal of service company wastes should be pursued with Alberta Environment and the local municipalities concerned. The Board will draw this matter to the attention of Alberta Environment.

It is ERCB policy that wastes produced at oil field operations should be disposed of in an environmentally safe manner. In view of the intense development taking place in the Lindbergh Field area, there may be a local need for a waste oil reclamation facility for the processing of oil field wastes. The Board encourages local oil field operators to investigate the possible development of such a facility.

4.7 Land Use

4.7.1 Lease Preparation and Size

EPSRA expressed a concern respecting the size and preparation of the Amoco well sites. It indicated that the Amoco well lease surface areas used were much larger than the ones currently used by the other operators. It suggested that Amoco should not be allowed to strip the topsoil from the entire lease area until it had been determined what kind of operations would actually be conducted at each particular site.

Amoco indicated that it required the entire lease area during steam stimulation operations. The seemingly large lease size was required to meet the normal ERCB equipment spacing requirements. In response to the concerns respecting the stripping of the entire lease site, Amoco indicated that it believed that it was more efficient and less damaging to strip the entire site rather than clearing a small area for initial operations and then coming back later to strip additional portions of the lease.

The Board is aware of the concerns regarding excessive lease size, however, it believes that the lease must be of sufficient size to allow for the installation of all equipment in accordance with the ERCB regulations. The need for a larger lease for steaming operations along with the necessary density of drilling are reasons why the Board believes that directional drilling from pads should be given serious consideration when projects are being planned. In this particular case, the Board did not hear any evidence to indicate that the lease size utilized by Amoco was having any unusual impact on other land surface uses at presently developed well sites. Consequently, it does not believe that any action is required.

The Board does not believe that the stripping of topsoil off the entire lease area at the outset would be a problem as long as proper stripping practices are carried out with the appropriate degree of supervision. In fact, it believes that a better soil conservation job can be accomplished by doing the entire site at one time as opposed to doing the same area in a piecemeal fashion. If it is subsequently determined that the entire lease site will not be required, it would then be possible to reclaim the unused portions of the lease.

4.7.2 Reclamation

EPSRA raised the issue of the need for proper site preparation to ensure the eventual successful reclamation of well sites and access roads. It expressed the opinion that proper topsoil stripping of the sites and proper storage of the topsoil during the period of active use of the leases was essential. It said that because oil development in the area is quite recent, local landowners and oil operators have little actual experience regarding the reclamation of well sites.

It was Amoco's position that it does properly strip and conserve the topsoil and that it will be able to successfully reclaim all sites disturbed. Amoco said that it will have to demonstrate to the landowner and the Land Conservation and Reclamation Council (Alberta Environment) that its obligation to successfully reclaim the disturbed areas is fulfilled in order to receive the required Reclamation Certificates.

The Board is generally satisfied with the soils handling procedures proposed by Amoco. It notes the concerns raised by EPSRA and also that the matter of site preparation, topsoil storage, and reclamation is dealt with by the Land Conservation and Reclamation Council. The Board intends to draw to the attention of the Council the evidence given at the hearing respecting the alleged improper site preparation practices and request that it review the matter and inform landowners in the area of its findings.

4.7.3 Impacts on Farming

EPSRA was concerned about the impact that surface facilities associated with the proposed Amoco project would have on farming operations. The specific issue was the impact overhead electrical powerlines running into the well sites or pads would have on the farmer's ability to use aerial operations in his farming program. It was EPSRA's contention that overhead electrical lines would severely limit the use or effectiveness of various aerial farming practices.

During the hearing, EPSRA's concern was satisfied by Amoco making a commitment to place the electrical lines underground at the request of the landowner.

The Board agrees that this commitment by Amoco should sufficiently mitigate the impact overhead electrical lines may have on aerial farming operations.

4.8 Protection of Shallow Aquifers

EPSRA, the Kadutskis, and Ms. Keith expressed a concern respecting the possible contamination of groundwater zones in this area that could occur as a result of drilling, inadequate surface casing setting depths, inadequate cementing of production casing, and water disposal operations. In their view, additional precautions should be taken to ensure the protection of the groundwater resources in the area.

Amoco indicated that it does not believe there is any danger of contaminating the groundwater sources in the Lindbergh-Elk Point area. It stated that 100 metres of surface casing will be run in all of the wells and that in its view this will cover all freshwater aquifers. In addition, Amoco has revised its cementing practices to ensure the quality of the cement job on the production casings. Cement bond logs are also run to ensure the quality of the cement around the casing and steam is injected at pressures below the reservoir fracture pressure.

Amoco also indicated that it will be conducting a water well sampling program in the vicinity of its project. Respecting water disposal operations, Amoco indicated that it is obliged to meet all of the ERCB water disposal requirements and therefore it is satisfied that there will be no dangers associated with this operation.

The Board agrees that adherence to sound well casing, cementing, completing, and operating practices should be fully effective in preventing contamination of groundwater aquifers. Freshwater zones will be protected by a combination of two layers of cement and two steel casing strings. As well, the Board notes that staff from its local field offices (in this case Bonnyville and Wainwright) and the Calgary office conduct ongoing surveillance of well completions to ensure their quality and integrity, and that problems are followed up immediately. The Board is satisfied with Amoco's well completion program and the steps that will be taken to ensure the integrity of those completions.

The Board notes that Amoco intends to conduct a water well sampling program in the vicinity of its project. The Board strongly endorses the concept of checking the quality and quantity of flow from surrounding water wells before and after project start-up to address concerns of landowners and occupants.

In regard to water disposal operations, as mentioned previously, this is a matter of separate application in which the method of well completion is given very special attention. As well, the applicant must satisfy the Board as to the suitability of the disposal zone to accept the quantities and rates of disposal fluids without affecting the integrity of the confining geological formations or of the cement bonds of the disposal well. In effect, the ERCB through its approval process applies the appropriate conditions to ensure the confinement of waste fluids to, firstly, the wellbore, and secondly, to the disposal zone. The integrity of the system is monitored to ensure compliance.

4.9 Seismic Impacts

EPSRA inquired as to whether Amoco would be conducting any studies in its project area concerning seismic activity resulting from cyclic steam injection. It cited a study of man-made seismicity in the Cold Lake area which suggested that earth tremors in that area were due to fluid injection in cyclic steam operations and could be related to steam injection pressures. Amoco indicated that it would be injecting steam below fracture pressure of the producing formation, and thus its operations would not result in such tremors. The Board is satisfied with Amoco's position with respect to potential seismic activity at its proposed project.

4.10 Well Spacing and Pad Drilling

EPSRA contended that if large-scale development of the area were allowed on 2-ha spacing using vertical wells, it would severely limit the amount of land that could potentially be farmed and in effect transform the land to purely industrial use. It suggested that present regulations intended to maintain compatibility between agricultural land use and well sites are inadequate.

Amoco noted that it would only be developing its 13-well thermal project using vertical wells on 2-ha spacing. The remainder of its 180 delineation and development wells would be drilled vertically on the 16-ha spacing currently existing on the Lindbergh Field. It agreed that the pad drilling concept would result in less surface disruption than vertical drilling and noted it is currently testing the concept with three such pads.

The Board shares the concern of EPSRA respecting the surface land use impacts that would result from development of the Lindbergh Field area using vertical wells drilled on 2-ha spacing. It believes that wells directionally drilled from a central pad would provide opportunities to minimize the disturbance to agricultural activity and also to properly manage any surface environmental impacts. The Board thus encourages the testing of the pad drilling concept.

4.11 Weeds

Three issues were raised regarding weeds. EPSRA was concerned that soil sterilants not be used on access roads or well sites to control vegetation as the residual effect of these sterilants is considerable and renders reclamation extremely difficult. Amoco assured EPSRA that its vegetation management program involved only use of herbicides commonly used for agricultural purposes.

The second issue involved the actual vegetation management program to be used by Amoco. EPSRA wanted details of the program. Amoco responded by stating that vegetation management is to be contracted out and the contractor will determine the specific program based upon need. In addition, spot control may be done using summer crews.

The third issue raised by EPSRA was the potential for introducing species of noxious weeds into the area as a result of moving equipment from other parts of the province and out-of-province into the area. EPSRA suggested that Amoco field personnel working in the area be educated in identifying species of noxious weeds on leases and access roads, so that these weeds could be destroyed before they become established. Amoco responded by saying that the vegetation management contractor will have such expertise and therefore it was not necessary to educate its field personnel in this regard.

The Board notes that the matter of weed control generally falls under county jurisdiction and that the use and control of herbicides is subject to Alberta Agriculture control. The Board is therefore satisfied that there are established provisions to meet EPSRA's concerns and is generally satisfied regarding Amoco's plans for weed control.

5 PROJECT LOCATION AND ACCESS

In addition to the broad environmental concerns dealt with in the previous section, the site-specific impacts of the proposed central processing facility and the 13-well thermal project were discussed at length at the hearing. Mr. and Mrs. D. Kadutski, whose home is located in the northeast quarter of section 29-55-6 W4M, expressed concerns regarding a number of matters which they believed would directly impact on them as their home is located across the road some 750 metres away from Amoco's proposed Phase 1 central processing facility and thermal project site. The Kadutskis questioned whether the proposed site for the processing facility was an appropriate one. Their greatest concern was the impacts caused by heavy truck traffic entering and leaving the proposed facility site located in the northwest quarter of section 28. They therefore argued that if the proposed site was approved, access to the plant should be from the east rather than the west as proposed by Amoco. The proposed processing facility and project site, the D. Kadutski home, and the two access alternatives discussed at the hearing are shown in Figure 2.

This section of the report deals with the proposed central processing facility location and access, and because of the importance of the issues at the hearing, it reviews the evidence in greater detail than for other issues. The Kadutskis are members of EPSRA and were generally supported in their views by the association. For convenience, the Board is including all of the evidence received on behalf of the Kadutskis in that which is attributed directly to them.

5.1 Central Processing Facility Site Location

5.1.1 Views of the Kadutskis

The D. Kadutskis expressed concern respecting the impacts of the central processing facility and the thermal project on themselves and their family during both the construction and operating phases because of the proximity of the proposed site to their home. They acknowledged that most of the impacts would relate to heavy truck traffic into and out of the site but also were concerned regarding noise from earth-moving equipment and pile-drivers during construction, plus drilling and service rigs, and pumps and other equipment at the processing facility. The Kadutskis did not consider that the site selection criteria used by Amoco had given sufficient consideration to potential impacts on local residents.

The Kadutskis pointed out that the proposed processing facility is a non-conforming use in the context of the agricultural area in which it is to be placed. Although they agreed that there is some advantage to locating the central processing facility close to the thermal project, they did not consider the facility location should be dominated by that factor. Instead they argued that siting the facility in the northeast quarter of section 28 (Lsd 16-28-55-6 W4M) would place the facility adjacent to the County road on the east side of section 28 and mean that the site would be 1 mile from each of the nearest three residences.

5.1.2 Views of Amoco

Amoco said that it first chose the 13-well thermal project location as the "best" location in terms of reservoir characteristics. For this purpose, it had regard for the following reservoir parameters.

- adequate pay thickness
- representative permeability and porosity
- oil saturation of at least 70 per cent
- absence of gas cap
- absence of bottom water
- good vertical continuity
- low-clay content in reservoir

Amoco went on to say that since there was a need for the central processing facility to process the steam-flood bitumen emulsions, and since these represented nearly half the total production expected during its Phase 1 operations, the best place would be adjacent to the ther-

mal project. In addition, the steam plant would serve both the thermal project and the central processing facility. Amoco said that if the facility was located in legal subdivision 16-28, as suggested by the Kadutskis, the surface heat loss would be doubled because of the extra distance.

Since there was a need to locate the facility alongside the thermal project, that introduced the following additional criteria which Amoco had regard for in the site selection process.

- central location respecting Amoco's lands
- potential for facility expansion
- local topography
- availability of water, power, and fuel

Amoco, when questioned, maintained that it also had regard for surface impacts on local residents when selecting the project site but that the D. Kadutski home was not built until after the site had been selected. Amoco added as another reason for not wanting to move the processing facility site farther east, that it had already purchased the land at the proposed location.

Amoco presented evidence suggesting that the installation of the Phase 1 central processing facility would create essentially no impact on neighbouring residences. It said that noise from earth-moving equipment would only occur during the short construction period and might be discernible but would not be measurable at the D. Kadutski residence given the 750-metre separation distance. Similarly, the pile-driving equipment would not create a problem, although during a very quiet period of the day it would likely be heard. Amoco also said it would outfit engines and other equipment with improved mufflers at its thermal project site and as a result, these would have little impact on the D. Kadutskis. The 13-well thermal project pumps would be electrified to eliminate motor noise and the hours of operation for service rigs would be restricted to 7:00 a.m. to 7:00 p.m. except during emergencies.

Amoco went on to indicate that it was investigating a recommendation from Bolstad Engineering Associates Ltd. that it place additional enclosures around power generating equipment, use higher quality mufflers, and generally buy and use only equipment which is planned to be as quiet as possible. With all of these measures, Amoco contended that the operations on the site itself would have little impact on the D. Kadutskis.

5.1.3 Views of the Board

The Board believes that most of the impacts referred to by the D. Kadutskis would result from traffic into and out of the central processing facility and thermal project sites. It further believes that these aspects of the problem should be addressed when dealing with the access to the site, and in this subsection is presenting its views only with respect to the site location.

The Board agrees with Amoco that there are valid reasons for locating the Phase 1 central processing facility adjacent to the thermal project. It also agrees that the proposed location of the thermal project is a proper one having regard for the relevant reservoir properties.

With respect to impacts on the D. Kadutski residence from operations on the site itself, the Board believes they would not be substantial given the separation distance of 750 metres and provided that the mitigative measures committed to by Amoco are adhered to. At the same time, the Board cautions that if any expansion of the central processing facility is contemplated, expansion in a westward direction towards the D. Kadutski residence may not be acceptable due to potential impacts. Any expansion of the facilities would of course be subject to further application to the Board and to a review by affected parties.

The Board recognizes that the central processing facility could have been located farther east alongside the thermal project. This would have been slightly farther from the D. Kadutski residence. However, in the Board's judgement, the impacts (leaving aside for the moment those related to traffic from heavy trucks which will be dealt with in a subsequent section) do not warrant a denial of the central processing facility application on grounds that the site is unacceptable.

5.2 Impacts from Traffic, Possible Mitigative Measures, and the Question of Site Access

5.2.1 Views of the Kadutskis

The D. Kadutskis stated that they were already subject to a great deal of noise from traffic related to the oil industry and if the proposed west access to the site was approved, the traffic impacts would be compounded. They said that the increased traffic would make the noise almost unbearable, create stress, eliminate opportunities to use their yard due to noise and dust, impact on planned hog production operations, and represent a safty hazard to their children.

In responding to a study by a noise expert, Mr. Bolstad, the Kadutskis questioned the validity of it because the traffic count and the noise measurements were carried out on different days. They also said that Mr. Bolstad incorporated several unacceptable assumptions into his noise impact studies, including for example that "jake brakes" would not be used by heavy trucks prior to turning into the proposed west access route.

The Kadutskis questioned the validity of the traffic estimates submitted by Amoco and stated that even accepting those estimates, there would be a significant increase over what now exists. It was their position that whether the traffic comes from the north or the south, it would turn on to Amoco's west access road close to the D. Kadutski residence. This would cause use of brakes, shifting of gears, and heavy acceleration, all of which would create noise.

The Kadutskis argued that the most effective form of mitigation of the impacts of traffic would be through "separation". This could best be achieved by changing the access road to the central processing facility and thermal project site to the east side of section 28 in place of the west side access. The Kadutskis argued that the proposed west access road would be a new road whereas east access already exists in the form of two lease roads into well sites (as shown in Figure 2 of this report). They said that the decision on whether to access the site from the east or the west should be made on the basis of the relative impacts of the two alternatives and not on the relative lengths or related costs.

The Kadutskis questioned a number of the elements of the evidence submitted by Amoco which supported the west access route over an east access. They contended that the relative costs of the two routes should primarily be a function of length and that Amoco was putting too much emphasis on the different road grades. They also pointed out that even though the east access road would be essentially double in length to the west access road, a number of Amoco's cost estimates were more than double for elements common to both options.

The Kadutskis raised the question of safety for loaded tank trucks exiting section 28 onto the County road. They suggested that since the west access road did not have a flat spot at the bottom of the grade prior to entry onto the County road, there was a greater potential for accidents compared to an east access where a long flat approach would exist. Additionally, according to the Kadutskis, there would not be a proper line of sight looking north at the intersection for the west access road.

In dealing with the suggestion by Amoco that an east access road would affect an equal number of other residences, the Kadutskis said that those residences are already on main oil industry roads and thus the incremental impact they would face would not be as significant as for themselves. The D. Kadutskis stated that if there must be an access road on the west side, there should also be one on the east side so that traffic could go in from the west and exit from the east or vice versa. This would at least reduce the impacts on their residence. The Kadutskis mentioned several other ways in which impacts of traffic could be mitigated. One involved limiting heavy trucking operations from 8:00 a.m. to 5:00 p.m. Monday through Friday with the exception of the construction period. They conceded that if construction was to proceed, the sooner it was finished, the better, in terms of noise impacts. Also, they proposed that enforcement of reduced speeds near their residence and proper road signs would assist in mitigating impacts.

Another way in which trucking impacts could be significantly reduced, according to the Kadutskis, would involve the immediate flowlining of raw bitumen emulsion (dirty oil) from producing wells to the central processing facility, and pipelining clean bitumen from the plant to the sales pipeline. This would significantly reduce the number of trucks required and thus the associated impacts.

Mr. Berrien, appearing on behalf of the Kadutskis, suggested that it would be practical to use an earth berm to shield the D. Kadutski residence from traffic noise. He suggested that a berm some 200 feet long, 100 feet wide at the base, and 15 feet high could be located west and slightly north of the D. Kadutski residence to shield it from the west access road intersection with the County road. Mr. Berrien suggested that this could be topped with a grove of trees which would also have some mitigative impact.

Finally, the Kadutskis suggested that if the project went ahead, regardless of the access route chosen or the other mitigative measures taken, ongoing periodic noise surveys would be desirable. These could be used to determine if noise levels were changing and if additional mitigative measures were necessary.

5.2.2 Views of Amoco

Amoco presented a noise study, carried out by Mr. Bolstad on its behalf, which indicated that the traffic resulting from the Phase 1 project would have only minimal impact on the D. Kadutski residence. The study involved a 22-hour noise survey conducted by Mr. Bolstad and a traffic estimate compiled by Amoco. Mr. Bolstad measured noise over a 22-hour period and extrapolated this to a 56.8 dBA Leq_{24}. Since these measurements included traffic noise, he made a calculation that the existing ambient noise without traffic would have been the equivalent of 53.8 dBA Leq_{24}. He then made a further calculation of what the ambient noise would be if the existing traffic was doubled. This amounted to 57.5 dBA Leq_{24}. On this basis, he concluded that the daily equivalent sound level would be increased by less than 1 dBA over the existing situation and that minimal mitigation is needed.

Mr. Bolstad suggested that his study would be accurate even though his noise measurements were only for a 22-hour period and the traffic survey was conducted on

a different day. He did agree that the noise measurement might have been taken on the Kadutski property itself rather than across the road but again suggested that this would not make a significant difference. He said that even though he was not responsible for the traffic count, he believed that the increase of 120 per cent in heavy truck traffic allowed for in his calculations was likely more than adequate.

Amoco stated that its reasons for proposing access to the central processing facility site from the west were as follows:

- it involved the minimum number of residences along the truck route to Highway 41
- there is a lower grade on the west access road and thus cost of construction would be reduced
- the County road along the west side of section 28 has already been upgraded and is better able to handle additional traffic than the County road on the east side
- the length of haul using the west access would be 1 mile less than if the east access was used
- the steeper grade on the east side would limit the weather conditions in which it could be used without major construction to make the route suitable for loaded trucks
- the total cost for a suitable east access road would be some $100 000 more than the cost of construction of a west access road
- the truck weigh scale in the central processing facility lay-out is planned for west access
- it is unlikely that the County would approve an east access route for the clean bitumen tank trucks.

Amoco indicated that it would be prepared to restrict the normal hours of trucking to daylight hours to minimize impacts on the D. Kadutskis. It also said that construction and drilling equipment would be trucked to the thermal project site by different routes if possible, to lessen the impact on the D. Kadutskis. Amoco indicated that it would require 2 years of well production experience before it would be in a position to commence installing flowlines to carry raw bitumen from producing well sites to the central processing facility. Also, the installation of a clean products pipeline to supplant tank trucking from the processing facility would eventually be planned, but not before a suitable period of production experience was developed to support design capacity estimates and to ensure the economic viability of pipelining. Amoco pointed out that on-site water disposal was planned from the start and this would negate the need for trucking of produced water out of the area.

In commenting on the possibility of a berm to shield the D. Kadutski home from the proposed site, Mr. Bolstad suggested that it would have to be so high and the base so wide that it would not be practical. He also indicated that a sound barrier fence would be unreasonable because of its height, the related cost, visual impacts, and the snow fence effect on the County road adjacent to it.

5.2.3 Views of the Board

There is little doubt that use of a west access to the proposed site will concentrate traffic in the vicinity of the D. Kadutski residence. Much of the traffic would be from the north and would turn east at a point approximately 120 metres northeast of the D. Kadutski residence as shown in Figure 2. Traffic from the south would be subject to a slow speed limit in the vicinity of the residence. Both forms of traffic would cause noise impacts on the D. Kadutskis and result in some traffic congestion.

The Board considers that the most significant advantages of the proposed west route relative to one from the east are that the west side County road is in better condition, the average trucking route would be shorter by about 1 mile, the grade is less steep, the access road itself would be one-half as long, and thus less land would be affected by construction, and finally and partially as a result of the foregoing, the cost of the west route would be less.

The key disadvantage of the west route is the related impact on the D. Kadutskis. On the other hand, if the traffic was not directed to the region of the D. Kadutski residence by use of a west access, it would have to pass by other residences to get to the east access route. Figure 1 shows the Bugera, Seniuk, and Chubey residences in addition to that of the D. Kadutskis. A review of Figure 1 and the access route alternatives shown on Figure 2 suggest that if the east route was to be used, much of the traffic would pass either the Bugera and Seniuk residences or the Chubey residence. Some of these are located essentially the same distance from the County road as is the D. Kadutski residence. Although these people were not at the hearing, this cannot be taken to indicate that they are indifferent to increased traffic since they had no knowledge that an eastern access route would be discussed. Assuming some split in traffic, part passing the Bugera and Seniuk residences, the other part passing the Chubey residence, the impacts would be less but still not insignificant compared to that affecting the D. Kadutskis where traffic is concentrated at a single point.

The Board therefore concludes that an eastern access would not have a significant advantage in terms of impacts on rural residents and would increase the truck hauling lengths considerably. The latter point would mean more total traffic, in vehicle miles, for the general area.

The Board has separately addressed the question of the acceptability of the impacts on the D. Kadutskis as well as other residents in the Phase 1 producing area. Having regard for the Bolstad study, the Board believes the noise impacts can be kept to an acceptable level if appropriate mitigative steps are taken.

The Board fully agrees that Amoco should maximize efforts to ensure that all truck drivers adhere to safety standards and minimize speeds and the use of jake brakes in the vicinity of all local residences including the D. Kadutski residence. Trucking should also be limited to daylight hours. The Board encourages Amoco to eliminate trucking on Sundays to the extent possible.

One of the most effective ways of reducing impacts would be to reduce the volumes of traffic. This can be accomplished by bringing forward the time at which pipelines are installed and used. The Board recognizes that a period in which to prove the economic feasibility of pipelines would normally be expected but in this instance believes that period should be shortened as much as practical. As stated previously, it will require Amoco to report on the feasibility of installing a products pipeline 6 months after the start-up of the central processing facility. Additionally, it will require an annual report from Amoco summarizing the situation regarding the feasibility of pipelining of well production to the central processing facility.

Continued use of field tank trucks rather than pipelining would be allowed only where it can be shown to be unreasonable to install field pipelines due either to the volume of fluid or the short time period over which the movements would take place.

With the above-mentioned mitigative measures, the Board believes impacts on the D. Kadutskis should not be unreasonable. However, it agrees with the D. Kadutskis that noise measurements should be taken prior to the commencement of construction of the project and that surveys should also be taken after it is in operation. If the measurements show that Mr. Bolstad's calculations respecting noise were inaccurate and that impacts are quite serious, further mitigative measures would have to be developed. Conceivably, these could take the form of either a berm (though the Board has some reservations about the space limitations for such a structure), or a requirement that pipelines be put in place to reduce traffic.

5.3 Fencing of Facilities

The Kadutskis expressed concern that some of the existing Amoco well sites and its ecology pit were not fenced sufficiently to prevent access by inquisitive children. They also asked that Amoco's proposed central processing facility and thermal project be appropriately fenced with an 8-foot chain link frost fence topped with barbed wire, and that proper locking gates be used specifically on the ecology pit which is located just north of their residence.

Amoco indicated that it planned to construct an appropriate fence around its central processing facility and thermal project. It noted that although the majority of its existing wells were not fenced, there were protective cages around the moving parts of lease equipment. With respect to its ecology pit, Amoco indicated the gates are locked at night unless a load of oil is to be taken from the pit during the night.

The Board recognizes the concerns of the Kadutskis respecting fencing of facilities and endorses Amoco's plans to fence around its central processing facility and thermal project. In the case of individual well sites, the Board notes that some sites may not require fencing under existing regulations. However, the Board would expect that Amoco would consult with the Kadutskis respecting the various Amoco sites near the Kadutski property. It believes that Amoco should, wherever practical, accommodate the requests of the Kadutskis not only with respect to the sites to be fenced but regarding the type of fence and the security it provides. The ERCB field staff is prepared to participate in any discussions respecting fencing, and in the event of disagreement between Amoco and the Kadutskis on either the need for or type of a specific fence, will decide the issue.

6 RESERVES, RECOVERY EFFICIENCY, AND OTHER TECHNICAL CONCERNS

6.1 Reserves and Recovery Efficiency

Amoco identified the zones of interest as the Cummings B and C sands of the Cold Lake Wabiskaw-McMurray Oil Sands Deposit. It believed the thickest sand development to be in the southwestern portion of the development area, pinching out to the northeast and thinning depositionally to the southeast. Amoco interpreted the sands to be bitumen-bearing with the exception of small scattered gas caps and some water to the west of the development area. Reservoir parameters on Amoco's Phase 1 lands and specifically on the lands selected for Phase 1 thermal development are shown in Table 2.

Amoco indicated that the 13-well thermal project site centred in legal subdivision 11-28-55-6 W4M was selected as the optimum location based on a number of reservoir criteria as well as surface considerations (including central location; potential for facility expansion; local topography; and water, power, and fuel sources). These reservoir criteria included adequate pay thickness, representative permeability and porosity,

bitumen saturation of at least 70 per cent of pore space by volume, absence of gas cap and bottom water, good vertical continuity, and low clay content in the reservoir.

The thermal project wells would utilize two existing wells along with eleven new wells which would result in 2.02-ha well spacing. These wells would form four adjacent 5-spot patterns, each with an enclosed area of 4.05 ha. It is noted that this well configuration contains one fully enclosed 4.05-ha 5-spot pattern. After each well has been cyclicly steam stimulated a sufficient number of times to establish heat communication between wells, four of the wells would be converted to continuous steam injection wells to enclose a central producing well and form a 5-spot steam drive. Amoco predicted a thermal recovery factor in the order of 35 per cent based on numerical reservoir simulation models. However, it qualified this prediction by noting that the recovery factor in other parts of the Phase 1 area could vary from 18 to 40 per cent depending on factors such as the amount of steam override or the presence of bottom water which would act as a thief zone. The 35 per cent thermal recovery efficiency predicted by simulation methods was based on a cumultive steam-oil ratio not exceeding about 4 or 5 m^3 of steam injection (water equivalent) to 1 m^3 of bitumen production.

The Board is in general agreement with Amoco's geological interpretation and, from mapping of the Phase 1 area, calculates the OBIP to be in the order of 62 million (10^6) m^3. The Board is prepared to book established reserves by primary production for the Phase 1 area based on a 2 per cent recovery efficiency and to consider an incremental recovery factor for thermal operations. The Board notes that Amoco's predicted 35 per cent recovery efficiency is not yet demonstrated. The Board is prepared to recognize 15 per cent ultimate recovery from the 13-well thermal project area at this time and intends to update this estimate as production history becomes available.

6.2 Impact of Water Disposal Operations on Recovery

Westmin, through cross-examination and closing argument, expressed a concern respecting the possible negative impact on its hydrocarbon recovery from the Clearwater zone associated with Amoco's water disposal operation through the 9-28-55-6 W4M well (9-28 well). Westmin indicated that it has identified some potential hydrocarbon-bearing zones in the Clearwater under its lands immediately adjacent to the Amoco disposal well and it wanted to know if Amoco had evaluated the potential impact of continued and possible increased disposal into the 9-28 well.

Amoco indicated that it is aware of the hydrocarbon potential of the Clearwater zone and that it believes there will be little if any effect on potential hydrocarbon recovery. By its interpretations, the hydrocarbon zone is separated from the disposal zone by a continuous shale barrier so that the disposal water should not invade the hydrocarbon zone.

The Board acknowledges Westmin's concern respecting continued water disposal into the Clearwater zone. It will ask the ERCB staff to review the subject water disposal approval respecting the concerns raised by Westmin and arrange a meeting to consider in much greater detail the interpretations put forward by Westmin and Amoco. The Board will consider this evidence in deciding whether the existing water disposal approval for the 9-28 well should be rescinded or amended.

TABLE 2 RESERVOIR PARAMETERS (as estimated by Amoco)

	Phase 1 Area	Thermal Project Area
Net Pay (avg.)	10 m (approx.)	12.2 m
Porosity (avg.)	30%	30%
Bitumen Saturation	70%	70%
Original Bitumen In Place (OBIP)	60 x 10^6 m^3	0.675 x 10^6 m^3
Estimated Recovery Efficiency	2%[1]	35%[2]
Estimated Bitumen Recovery	(1.2 x 10^6 m^3)	(236 x 10^3 m^3)

Notes:

[1] Prior to conversion to thermal recovery in Phases 2 and 3. Ultimate recovery by primary operations is estimated to be 4 per cent.

[2] From enclosed pattern.

6.3 Cyclic CO_2 Stimulation and Corrosion

EPSRA expressed concern with the possibility of corrosion occurring in those wells that would be cyclicly stimulated using CO_2. It also contended that objectionable odours had resulted when CO_2 was injected at other operations. Amoco indicated it would be injecting CO_2 in batches and would be displacing each batch into the reservoir to prevent any contact with moisture (steam) thereby minimizing the potential for corrosion. It also noted that it would be using corrosion coupons and periodic visual inspection to monitor for corrosion in those wells involving the use of CO_2.

The Board is satisfied with the measures Amoco intends to take to minimize and monitor for corrosion as related to CO_2.

6.4 Produced Water Reuse

Phase 1 of the proposed project does not provide for any treatment or reuse of produced water in its design. However, Amoco indicated its intent to investigate the reprocessing and reuse of produced water if it proceeded with Phases 2 and 3 of its development. It noted that produced water samples would be analysed during Phase 1 in preparation for reprocessing studies. In its application, Amoco stated that its aim would be to recycle a minimum of 80 per cent of produced water during Phases 2 and 3.

The Board believes that it is in the oil sands operators' best self-interests to take an aggressive approach in developing water reuse technology, keeping in mind the package of technical, economic, and environmental problems that relate to the water use and disposal issue. As well the importance of water resources to the agricultural community was clearly expressed by interveners at this hearing and is underlined in such studies as Alberta Environment's Cold Lake-Beaver River Water Management Study. The Board believes this issue will have increasing importance as commercial projects, such as Amoco's, are expanded. The Board notes that Alberta Oil Sands Technology and Research Authority has launched a joint research study, in which several oil sands operators are participating, aimed at developing viable technology for reprocessing produced water. The Board also notes that recycling of the order of Amoco's 80 per cent target is already being achieved at the Esso Cold Lake Project. These experiences encourage the Board to expect that the reuse of produced water will eventually satisfy a large fraction of operator water requirements in the Lindbergh Field area.

7 ECONOMIC, SOCIAL, AND OTHER CONCERNS

In addition to the issues addressed earlier, the Board wishes to comment on some broader matters that relate to regional and provincial impact assessment.

7.1 Marketing and Diluent Availability

Amoco submitted that cold production from its operations in the Lindbergh Field area is currently trucked to Husky's cleaning facility in Lloydminster where it is blended with condensate and pipelined to the Hardisty pipeline terminal. Amoco stated that it would continue this arrangement until such time as the viability of pipelining sales oil directly from the central processing facility site could be proven. The target market for production is located in the Northern Tier U.S., an area that Amoco suggested would continue to provide a significant market for Canadian heavy oil and bitumen. Diluent requirements were estimated by Amoco using a ratio of 3 Lindbergh bitumen to 1 diluent to be 190 m^3/d for the Phase 1 project. Amoco submitted that the Alberta Petroleum Marketing Commision (APMC) had given a written commitment to provide sufficient diluent for the initial phases of the Elk Point Project.

The Board accepts the market assessment provided by Amoco and in light of the commitment provided by the APMC, the Board does not believe that market access or diluent availability would pose significant constraints on the Phase 1 project.

7.2 Socio-economic Impact

Amoco estimated expenditures during the first 4 years of the Phase 1 project would be approximately 87 million as-spent dollars. These expenditures were expected to result in 30 to 50 construction jobs and approximately 20 additional operations jobs. Amoco submitted that it does not anticipate a requirement for expanded community service facilities to result from Phase 1 employment.

The Town supported the Amoco view and indicated that available housing would be sufficient to accommodate the entire construction work force. The Town, the County, and Ms. Darling all supported the project on the basis that it would have beneficial economic impacts on the area.

Concerns regarding the potential for road damage due to increased heavy truck traffic were expressed by EPSRA, the Kadutskis, and the Town. The County acknowledged that increased road maintenance and upgrading costs would accompany the development. Further, the County indicated that these costs would be manageable since road upgrading grants are available from the provincial government and the level of taxes for oil field development is expected to increase.

Normally, when it has considered the nature and extent of the socio-econcomic impacts that were expected to accompany commercial oil sands developments, the Board has estimated the potential for net economic benefits. Generally, these benefits translated into positive

regional and provincial impacts and these were, at least in a qualitative sense, then compared with the potential for stress on the regional infrastructure. This approach has not been fully pursued here, due to the nature of the Phase 1 proposal. Amoco submitted that the nature and scope of Phase 1 is investigative and confirmed that in a technical sense, Phase 1 represents an experimental proving-up portion of what is hoped to be a commercial scheme. In light of the uncertainties that surround the economic and technical parameters at this time, Amoco submitted that an economic evaluation of the full development would be premature. The Board believes, as it has indicated in section 6.1, that a recovery efficiency of 15 per cent of bitumen in place is reasonably assured. However, details concerning development and operating costs render economic projections rather uncertain at this time. The Board therefore accepts Amoco's position regarding economic evaluations and since it is considering only Phase 1, the Board does not believe there is a need for a detailed benefit-cost analysis nor to scrutinize the proposal for economic viability. However, the Board would require that a detailed economic viability analysis and a socio-economic study accompany later applications for Phases 2 and 3.

The Board generally views the increased employment opportunities as a potentially positive regional impact and expects the project could be built and operated with a minimal net impact on the regional infrastructure.

7.3 Public Informational and Communications Programs

One recurring element in the submissions made by several of the hearing participants was the perceived need for an open flow of information between Amoco and local impacted interests. EPSRA indicated that with respect to environmental matters, potentially impacted residents should be provided access to the results of all special impact studies and ongoing monitoring programs. Further, it recommended that in future when developments such as the periodic steam stimulation of wells in Area B, or the installation of aboveground powerlines might be contemplated, Amoco should undertake to inform all individuals owning, living on, or farming potentially impacted lands.

An instance of communication problems was that concerning D. Kadutski's arrangements to build a country residence on section 29-55-6 W4M in the spring of 1984, while Amoco had, about the same time, initially announced its Elk Point Project. Neither the Kadutskis nor Amoco were aware of the detailed plans that each had that would eventually lead to the problem of the D. Kadutski home being built across the road from Amoco's proposed project. Mr. D. Kadutski indicated that he did not have full knowledge of Amoco's development proposal for section 28 or of its potential impacts until September 1984. Amoco acknowledged that it was aware of D. Kadutski's plans in April and only in a general way advised the Kadutskis that it would be locating a thermal project and central processing facility on the offsetting section 28 lands. In this particular example, the absence of mandatory public notification procedures and ineffective voluntary procedures may have caused both parties (Amoco and the Kadutskis) to be proceeding at cross-purposes with no effective way of being made aware of each others respective plans.

The Town submitted that development in the Lindbergh area is accompanied by the need for an ongoing exchange of information among administrative, corporate, and resident interests. In the Town's view, this need could be satisfied through the formation of a citizens' advisory committee.

Amoco indicated that it had undertaken a public relations program in the community starting in the summer of 1984. A continuing need for this type of work was recognized by Amoco and for this reason it committed to providing an ongoing program of presentations designed to update local residents as to the status of its project. Amoco agreed that this program should recognize the seasonal commitments of the agricultural community. In addition, Amoco stated that it was committed to releasing all environmental monitoring information to the public. Local residents were invited by Amoco to voice their concerns to any of the Amoco employees or directly to the local Amoco field office. Further, Amoco stated that it would be prepared to participate in a committee drawn from oil companies, local residents, and other groups.

Recognizing that objections to the siting or operation of future steam stimulation tests may arise, Amoco committed to informing landowners prior to a test and referring unresolved problems to the Board.

The Board continues to believe that the timely provision of information pertaining to plans for industrial development or ongoing operations is a prerequisite to the satisfactory coexistence of agricultural and industrial interests. The Board thus encourages all of those activities that are designed to enhance the timely exchange of information and concerns between developers and local residents.

The Board endorses the recommendation of the Town respecting the formation of a citizens' advisory committee. It is aware of similar committees that have been formed in other situations and that are now contributing significantly to an increase in public awareness.

The Board notes that during the public hearing, some of the issues that were raised dissipated when the posi-

tions of all parties were clarified. The Board has concluded that much of the cross-examination that occurred might have been avoided had Amoco provided a detailed public disclosure of its plans to local residents in March 1984 and had the parties communicated more fully with one another during the subsequent planning stages. In this regard, the Board is of the view that the responsibility of informing the public rests firmly with the applicant. However, subsequent concerns by residents must clearly be communicated back to the applicant, prior to a public hearing, for meaningful discussions to take place. As well, the Board assumes that local municipal authorities would automatically provide information and respond to inquiries respecting industrial activities that might impact on a local landowner or occupant.

The Board expects that the benefits of public information and communications programs are now more fully appreciated by those who observed or participated in the proceedings and that this will lead to an increased exchange of information and views in forums less formal and more efficient than a hearing.

7.4 Need for Regional Development Inquiry

EPSRA recommended that the Board undertake to organize comprehensive public hearings and impact studies that would be designed to cover the oil sands and heavy crude oil regions of northeastern Alberta. The Board has considered this recommendation and even though its views in this regard do not relate to its decision respecting the Amoco application, it wishes to place them on record.

The Board is well aware that oil sands development has been significantly stimulated over the past 2 years by the emergence of new market opportunities and the provision of special fiscal incentives by provincial and federal governments. The result has been a large number of applications to the ERCB for well spacing, facility, and production scheme approvals. Meanwhile, development in these areas has proceeded coincident with the drafting of the regulations that are eventually to accompany the newly enacted Oil Sands Conservation Act. The Board recognizes this as a deficiency which it must resolve as promptly as possible in order to provide a framework for orderly development in the area. One complicating feature has been the absence of reasonable certainty that the Lindbergh area would be developed on anything more than a less intensive conventional oil pattern that is adequately accommodated by existing oil and gas development regulations. Another is that there are elements of the overall problem, such as regional planning, transportation, and land-use matters, that must be considered and decided by parties other than the Board. Additionally, the Board has found from experience that the broad omnibus hearings do not always bring forth the evidence necessary to deal with the problems being investigated.

For these reasons, the Board does not intend to hold a general inquiry on regional development as proposed by EPSRA. However, as a means of promoting more orderly practices respecting oil field facilities and operations in the Lindbergh area, the Board intends to issue a directive that will outline the nature of the existing regulatory environment, and present its views regarding further regulatory standards that should be introduced. The directive will also identify matters of general concern that have been brought to the Board's attention over the past year and the manner in which they are, and should be, dealt with. It would be the Board's intention, following broad circulation of the directive and its use on an interim basis, to regularly update it to reflect experience and changing circumstances.

8 DECISION

The Board hereby approves Application 840227 by Amoco for Phase 1 of a commercial oil sands project in the Lindbergh Field area including installation of a 13-well thermal project, an adjacent central processing facility, the drilling of some 160 delineation and development wells and the cyclic steam/CO_2 stimulation of up to 20 of these wells. Subsequent phases will require further applications to the ERCB.

The approval of Phase 1 is subject to all of the undertakings given by Amoco in the application and at the hearing and to the conditions set out in this report. Conditions of particular note are as follows:

(a) Amoco will be required to submit an initial report within 6 months of start-up of the project, and subsequent reports on request by the ERCB, detailing efforts to minimize traffic impacts in the general area.

(b) Amoco will be required to submit a report on the feasibility of a products pipeline 6 months after the start-up of the central processing facility.

(c) An annual report will be required, beginning 12 months after commencement of thermal project operations, summarizing the up-to-date situation respecting the use of flowlines to move raw well production to the central processing facility in section 28. Continued use of field tank trucks to haul raw production will be permitted only where installation of flowlines would be unreasonable.

(d) A sound survey at the D. Kadutski residence, suitable to the Board, will be required before construction and operations commence. Additional sound surveys will be required after operations are under way. Further mitigative measures may be required if the noise impacts of the Amoco facilities are significantly beyond those estimated by Amoco at the hearing.

An approval of the project will be issued in the near future following receipt of approval from the Minister of the Environment, the Minister of Energy and Natural Resources, and an Order in Council authorizing the granting of the approval.

DATED at Calgary, Alberta, on 28 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

N. A. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Board Member

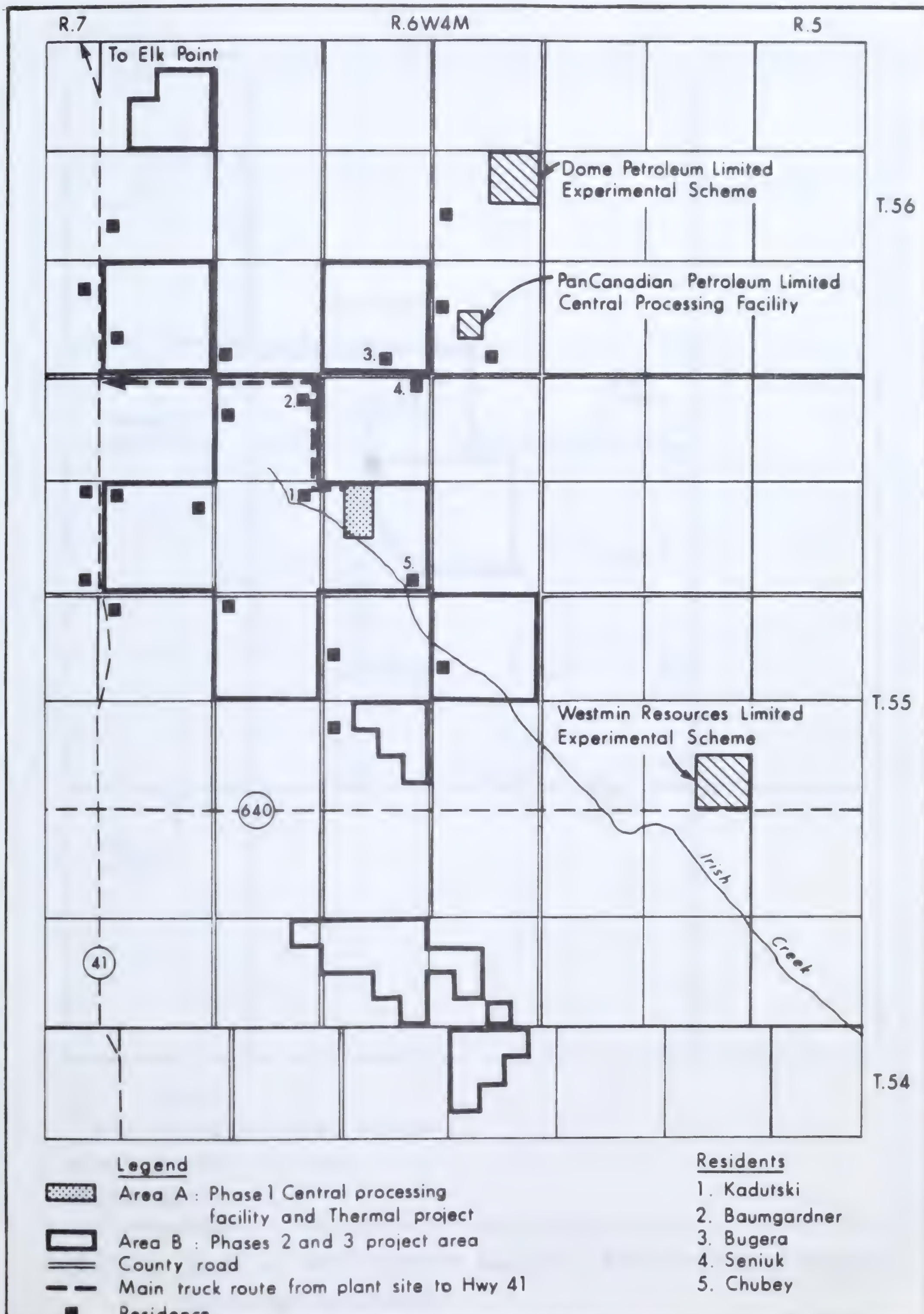


FIGURE 1 AMOCO ELK POINT PROJECT AREA

D85-15

ERCB

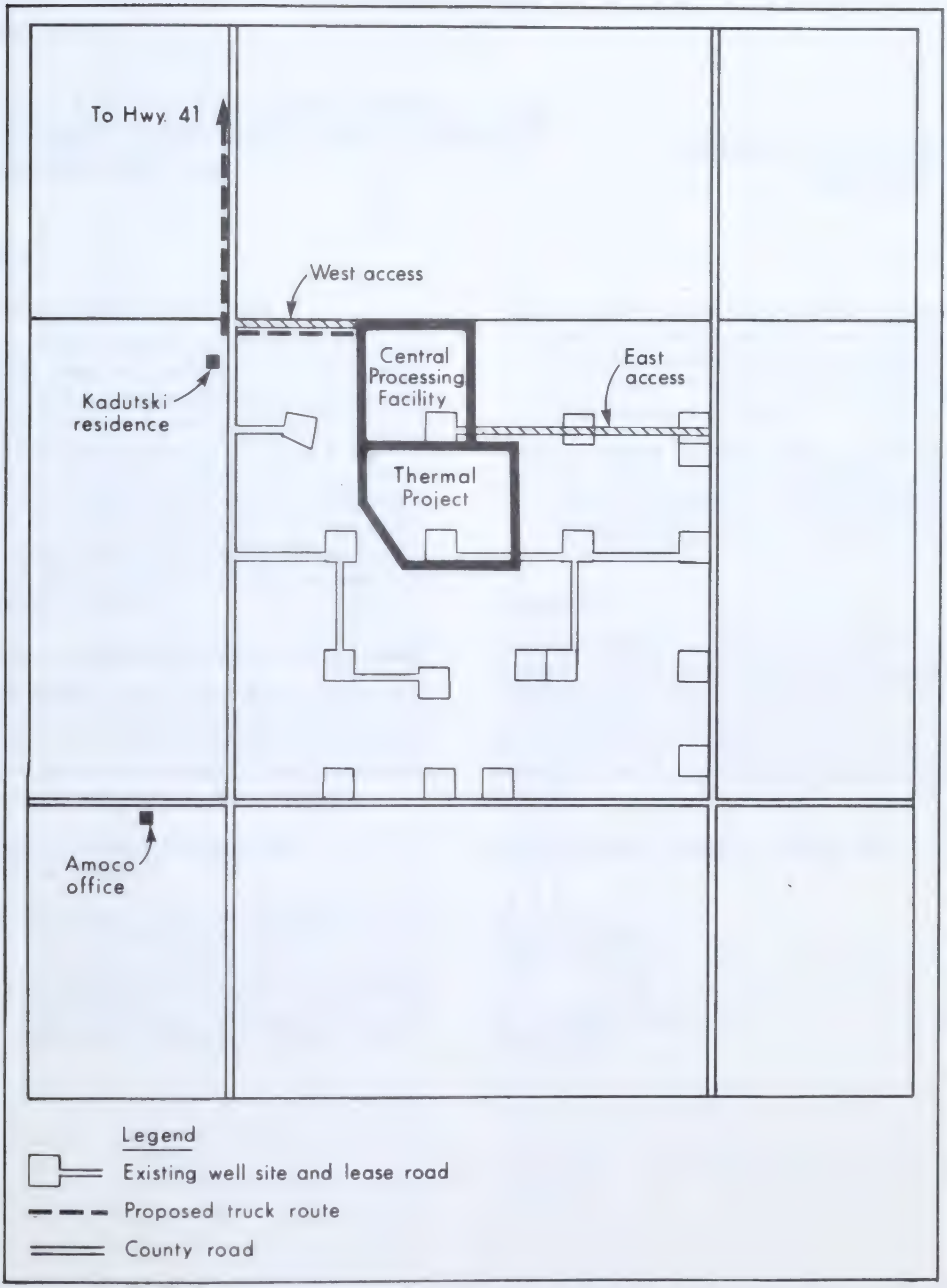


FIGURE 2 CENTRAL PROCESSING FACILITY AND THERMAL PROJECT
Section 28-55-6W4M

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

AMOCO CANADA PETROLEUM COMPANY LTD. COMMERCIAL OIL SANDS PROJECT (PHASE I) LINDBERGH SECTOR

Addendum to Decision D 85-15
Application 840227

ERRATA

1. Page 1, section 1, Introduction

The sentence "Phase 1 would consist of a 13-well cyclic steam and steam-flood stimulation project developed on 2-hectare (ha) well spacing and a 640 cubic metres per day (m^3/d) bitumen cleaning plant (central processing facility)[1] in Area A as shown on Figure 1" should read "Phase 1 would consist of a 13-well cyclic steam and steam-flood stimulation project developed on 1-hectare (ha) well spacing and a 640 cubic metres per day (m^3/d) bitumen cleaning plant (central processing facility)[1] in Area A as shown on Figure 1".

2. Page 8, section 4.10, Well Spacing and Pad Drilling

The sentence "Amoco noted that it would only be developing its 13-well thermal project using vertical wells on 2-ha spacing" should read "Amoco noted that it would only be developing its 13-well thermal project using vertical wells on 1-ha spacing".

3. Page 14, section 6.1, Reserves and Recovery Efficiency

(a) The sentence "the thermal project wells would utilize two existing wells along with eleven new wells which would result in 2.02-ha well spacing" should read "the thermal project wells would utilize two existing wells along with eleven new wells which would result in 1-ha well spacing".

(b) The sentence "these wells would form four adjacent 5-spot patterns, each with an enclosed area of 4.05-ha" should read "these wells would form four adjacent 5-spot patterns, each with an enclosed area of 2.02-ha".

(c) The sentence "it is noted that this well configuration contains one fully enclosed 4.05-ha 5-spot pattern" should read "it is noted that this well configuration contains one fully enclosed 2.02-ha 5-spot pattern".

COMMENT

The original application requested approval of 2-ha well spacing for the 13-well thermal project but this requested well spacing was changed to 1-ha spacing in a subsequent submission by the applicant. The Board was conscious of this change in well spacing when making its decision but this was not reflected in Decision Report D 85-15.

DATED at Calgary, Alberta on 7 March 1985.

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

WILLIAM LUCHYK
ENERGY RESOURCES CONSERVATION ACT
SECTION 42 REVIEW OF A
HUSKY OIL OPERATIONS LTD.
REMEDIAL CEMENTING PROGRAM

Decision D 85-16
Application 850170

1 THE APPLICATION AND HEARING

Mr. William Luchyk and Mrs. June Luchyk (the Luchyks) applied for a review of an approved Husky Oil Operations Ltd. (Husky) remedial cementing program for the well, HUSKY ET AL WILDMERE 5C-18-47-4 (W4M) (the 5C-18 well). The remedial program is intended to correct a gas flow to surface from the production casing-surface casing annulus of the 5C-18 well and is part of a complete abandonment program. It was the Luchyks' contention that the water quality in their domestic water well is being adversely affected by the 5C-18 well, and that the use of acid in the proposed remedial program would cause further quality deterioration. The application for review was considered, and the Board directed that the matter be set down for hearing pursuant to section 42 of the Energy Resources Conservation Act. A public hearing of the application was held in Lloydminster, Alberta, at the Wayside Inn on 22 February 1985, before Board Member, L. A. Bellows, P.Eng.

2 THE ISSUES

The Board believes the issues relating to the application to be:

- whether the Luchyks' water well is being adversely affected by the 5C-18 well,
- the need for the remedial program,
- the need for the use of acid in the remedial program.

3 PRELIMINARY MATTERS

- At the beginning of the hearing, Mr. Johnston, solicitor for the Luchyks, raised the question of the Luchyks' eligibility for local intervener's costs. The Board did not rule on the application, indicating that local intervener cost status could be determined when an application for costs was submitted to the Board.
- Mr. Gow, a witness for the Luchyks, stated the concerns of the agricultural community regarding the impact of oil industry operation in general on rural domestic water wells. Because this general question was not within the scope of the hearing, the Board is not prepared to comment.
- The Luchyks stated no serious discussion with Husky had been initiated regarding the water well problem and their perception that the problems were caused by communication with the 5C-18 well. The primary reason for discussion not occurring was the existence of other disputes between the Luchyks and Husky.

  The Board has expressed the view that it believes many problems may be resolved by improved communication between landowners and companies. The Board is concerned that there appears to have been virtually no communication in this case. The Board intends to pursue this matter in future disputes, perhaps through its field staff, through its meetings with surface rights associations, and discussions with industry.
- The Board notes that Mr. Luchyk gave evidence that he had installed gauges on the 5C-18 well, taken water samples, and on occasion bled pressure off the wellhead, all without Husky's knowledge or comment. The Board is compelled to comment that such actions may be in contravention of the Oil and Gas Conservation Act and are of concern, particularly with respect to safety.

4 BACKGROUND

The 5C-18 well was drilled in July 1976 and completed in the Lloydminster sand. Surface casing was run to 102 metres (m) and cemented full length. Production casing was run and cemented full length. The cement in the upper part of the well is poor as evidenced by the flow of small quantities of water and varying rates of gas from the surface casing-production casing annulus.

In April of 1976, the Luchyks' water well was drilled approximately 81 m from the 5C-18 well to a depth of about 30 m.

5 THE LUCHYKS' VIEWS

The Luchyks submitted that communication existed between their water well and the 5C-18 well by virtue of a series of pressure-related tests he had conducted.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
William and June Luchyk (the Luchyks) P. T. Johnston	W. Luchyk J. Luchyk G. Gow
Husky Oil Operations Ltd. (Husky) B. F. Thurgood	C. A. Nygren, P.Eng. R. Clissold, P.Geol.
Energy Resources Conservation Board staff H. R. Hansford J. S. Fraser	D. R. Shaw D. K. Boyler, C.E.T.

Because communication existed, formation fluids were entering the fresh water aquifer with a resultant deterioration in water quality. It was their further contention that this hypothesis was supported by the results of a series of water analyses from their well, together with the appearance on an intermittent basis, of black or somewhat foul smelling water. They further submitted that gas was now present in their water well which presents a potential safety hazard.

The Luchyks submitted that if Husky were allowed to proceed with the remedial program as approved, the use of hydrochloric acid would cause further deterioration in water quality and could pose a health hazard.

The Luchyks agreed that, if the Board conditioned an approved remedial program to require monitoring of their well, they would allow Husky to install monitoring devices.

6 THE BOARD STAFF'S VIEWS

Board staff stated that the water analyses submitted by both the Luchyks and Board staff did not indicate a significant deterioration in quality compared to an analysis taken in December of 1976, the year the well was drilled. The staff stated that the quality of the water was not good by drinking water standards, and never had been.

Board staff suggested that the black water that was present from time to time in the Luchyks' water system was probably caused by the presence of dead iron reducing bacteria. They further suggested the occasional sewer-like smell could be caused by the presence of sulphate reducing bacteria.

7 HUSKY'S VIEWS

Husky stated that, after setting an abandonment plug over the Lloydminster sand in April 1984, they had perforated the well casing at 128-131 m KB and tried to establish a water feed rate in attempt to stop the gas flow from the annulus. No acid was used due to concern over possible groundwater contamination and the program was not successful.

In May 1984, the interval 128-131 m KB was hydra-jetted, washed with acetic acid, and squeeze cemented. The program was not successful. In October 1984, the cement remaining from the squeeze was drilled out and gas was found to be entering the production casing. Additional logging indicated a possible porous zone at 160-164 m and this zone was perforated. Husky submitted a remedial program to the Board which included acidizing the interval 160-164 m with hydrochloric acid. Board staff approved the program subject to conditions including:

> "The acid treatment will be eliminated should a sufficient feed rate be observed during step 6 of your program," and "The water well at Lsd 5-18-47-4 W4M will be monitored using a suitable pressure recorder throughout the entire workover, subject to the landowners agreement."

Husky submitted that, if a water feed rate cannot be established, it will be necessary to acidize in order to accomplish a successful cement squeeze and stop the gas flow up the outside of the production casing. Husky also stated that its calculations showed a measurable water level change would occur at the Luchyks' well within 28 minutes assuming direct acid injection into the water sand at the 5C-18 well at a rate of 50 litres per minute (l/m) or in 5 minutes at 150 l/m. The calculations, which admittedly included many assumptions, were intended to illustrate that, if direct communication exists between the wells, it could be detected very quickly. Husky also postulated that if there was evidence of acid entering the aquifer, the acid could be recovered by lowering the water level in the 5C-18 well and reversing the flow.

Commenting on the results of the water analyses submitted by both the Luchyks and Board staff, Husky was of the opinion that there were no indications of significant change.

Husky submitted that the cause of the black water present from time to time in the Luchyks' water system was a release into the system of dead iron reducing bacteria. The smelly water was due to the possibility of the presence of a sulphate reducing bacteria, not usually related to oil-field activity.

Commenting on the presence of gas in the Luchyks' water well, Husky stated that this situation was not uncommon in fresh water wells and occurs naturally in approximately 1 per cent of all domestic water wells in Alberta. In fact, Husky was aware of other water wells in the area which also had gas present.

8 VIEWS OF THE BOARD

The Board appreciates the Luchyks' concern for their water supply. It can also appreciate how the tests conducted by Mr. Luchyk could cause him to conclude that communication exists between the two wells. However, the Board believes that the results of the tests conducted by Mr. Luchyk are not conclusive, primarily due to the methodology employed. It further believes that the presence of gas in the Luchyks' water well is not conclusive proof of communication since this is not an uncommon phenomenon throughout Alberta. It is the Board's view that communication has not been established.

The Board heard testimony from qualified witnesses who indicated that the water analyses submitted did not, as the Luchyks contend, show a deterioration of water quality over time. It also heard testimony from the same witnesses which provided logical explanations for the occasional appearance of black or foul smelling water in the water system. The Board does not believe that the available analyses demonstrate any deterioration of water quality in the Luchyks' well.

The Board notes that Husky was requested by the ERCB staff to correct the problem at 5C-18 as part of an abandonment program for the well. The Board agrees that all flow from a well must be stopped before its abandonment is complete. Accordingly, it agrees that a remedial program is necessary.

The Board, having determined that the question of communication between the Luchyks' water well and the 5C-18 well has not been answered conclusively and that a remedial program is required to stop the gas flow from the 5C-18 well, must next determine whether the use of acid in the remedial program is appropriate. It believes that if a water feed rate cannot be established, acid should be used with appropriate safeguards to ensure that if communication between the wells does exist, the Luchyk water well will not be affected.

9 DECISION

The remedial program as submitted to the Board and approved on 3 January 1985 by the Board's Wainwright staff is hereby confirmed subject to the following conditions:

(a) The Board's Wainwright office shall be notified in advance of commencement of any remedial program operation.

(b) Acid shall not be used in the program without the specific approval of the Board's Wainwright office.

(c) A water level measuring device shall be installed in the Luchyks'water well before any acid squeeze is commenced and the acid squeezing operation shall be discontinued if the water level measurement indicates communication between the 5C-18 well and the aquifer.

DATED at Calgary, Alberta, on 28 February 1985.

ENERGY RESOURCES CONSERVATION BOARD

L. A. Bellows, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ESSO RESOURCES CANADA LIMITED APPLICATION TO PROCEED WITH PHASES V AND VI OF THE COLD LAKE PROJECT

Decision D 85-17
Application 850037

1 APPLICATION

Esso Resources Canada Limited (Esso) applied on 11 January 1985 under clause 2 of Approval 3950 to proceed with Phases V and VI of the Cold Lake Project.

Approval 3950, issued in September 1983, approved the eventual production of 25 400 cubic metres per day (m^3/d) of crude bitumen on the basis of phased development from the Cold Lake Project Development Area as shown in Figure 1. Esso has received approval permitting the production of 6000 m^3/d under Phases I, II, III and IV.

The details of Phases V and VI under the current application are summarized as follows:

- Crude bitumen production rate of 3000 m^3/d from 6 sections of land as shown in Figure 1.
- 280 initial wells to be directionally drilled on 1.62-hectare spacing in clusters of 20 wells.
- Production levels to be maintained over the project life by developing up to 40 additional wells per year.
- Central plant facilities to be constructed on the same site and integrated with the facilities of Phases I and II.
- Fresh make-up water requirements during steady state operating conditions can be met within the limits of existing water withdrawal licences from Cold Lake and Ethel Lake.
- Start-up period to require additional volumes of fresh make-up water to be obtained through a groundwater diversion system.
- Additional deep well disposal requirements of 400 m^3/d and additional sulphur dioxide emissions of 1.25 tonnes per day.
- Additional diluent requirements of 1500 m^3/d.
- Construction to begin mid 1985 with plant start-up during the second quarter of 1986.
- On-site peak construction to require between 500 and 600 workers, permanent operations work force to be expanded by 70 people, and ongoing construction activity to generate 40 jobs.
- Socio-economic impacts can be accommodated within the existing infrastructure and services of the region.
- Continuation of programs to provide information and assistance to local communities respecting employment and business opportunities.

Through a series of meetings and open-house programs, Esso presented details of the Phases V and VI development to business, public interest, and Native groups, and municipal and provincial government representatives. It reported a general positive response to plans to implement Phases V and VI. However, some concerns were expressed regarding the water management plan for the Cold Lake Region and the quantities of groundwater required to satisfy the start-up of Phases V and VI. In addition, Esso reported that the Cold Lake Indian Band were pleased with business and employment opportunities, but reiterated its ongoing concerns respecting social areas. Also, the Municipal District of Bonnyville raised the issue of tax sharing with the provincial government in relation to road maintenance costs.

2 SPECIFIC DETAILS

The Board has reviewed the details of the program for implementing Phases V and VI and finds that they are essentially the same as the programs for previous phases. In this regard, the Board is satisfied that the program for these next two phases is technically sound and will conform with the terms of Approval 3950.

However, the Board has considered two issues of local concern and comments on these in the following passages. These concerns are:

- Additional fresh make-up water required during the start-up period of Phases V and VI.
- Changes to the socio-economic impacts.

3 ADDITIONAL FRESH MAKE-UP WATER REQUIRED DURING START-UP PERIOD OF PHASES V AND VI

Esso currently obtains the necessary amounts of water for the operation of the Leming and May-Ethel experimental schemes and Phases I to IV of the Cold Lake

Project through a combination of recycling all produced water from the projects and adding fresh make-up water from Cold Lake and Ethel Lake.

Recycled produced water usually accounts for about 65 per cent of the steam boiler feed water with the remaining 35 per cent from fresh water sources. For the latter, Esso holds licences under the Water Resources Act for a maximum withdrawal rate of 19 725 m^3/d of fresh water: 17 808 m^3/d from Cold Lake and 1917 m^3/d from Ethel Lake.

During the start-up period of Phases V and VI, a total of 27 225 m^3/d of fresh make-up water would be required for the combined experimental and commercial operations. In accordance with Esso's present plans, this would occur over an 8-month period from March 1986 to November 1986, following which the make-up water requirements would fall to a level which could be accommodated within the existing licence provisions.

To meet the additional 7500 m^3/d peak water requirements, Esso applied to install a groundwater supply system. On 30 April 1985, the Controller of Water Resources granted Esso a Temporary Permit for a groundwater diversion system located in NE 1/4-12-65-4 W4M and SW 1/4-22-65-4 W4M. The permit specifies a withdrawal limit of 1.3 million cubic metres and has a termination date of 31 December 1986.

The Board notes that, starting with the hearings respecting the original Esso Cold Lake Project (ERCB Report 79-E and ERCB Decision 81-C) and the subsequent inception of the Esso Phased Cold Lake Project (ERCB Decision D 83-21 and D 84-16), the questions of water use, fresh make-up water sources, produced water recycle, and waste water disposal have been given detailed attention.

The Board has reviewed the Temporary Permit (30 April 1985) for groundwater diversion and sees that it continues to reflect the tenor of careful attention to protection of fresh water sources. The permit places a cumulative limit on the quantity of withdrawals and the time period over which those may occur. As well as setting out a number of other safeguards, it requires that a monthly summary of monitoring, part of which must be prepared by an experienced professional groundwater specialist, be submitted to the Controller of Water Resources. Copies of these summary reports must also be supplied to the Cold Lake Community Advisory Committee and the Cold Lake Indian Band.

On the foregoing considerations, although the Board continues to hold the view that the long term water management plan being developed by Alberta Environment for the region must represent the bulwark for long-term fresh water use allocations, the Board is satisfied that the Temporary Permit is acceptable and within the spirit of careful water use planning.

4 CHANGES TO SOCIO-ECONOMIC IMPACTS

Esso proposed to begin construction of Phases V and VI by mid-1985 and start-up steam injection operations during the second quarter of 1986. The construction stage would require between 500 and 600 workers at its peak. The permanent operations work force at Cold Lake would be expanded by 70 people and ongoing construction activity related to Phases V and VI would generate 40 permanent jobs.

Esso believes that the social impacts of Phases V and VI can be managed within the current infrastructure and level of services in the region.

Esso intends to continue providing information programs and assistance to local communities with respect to employment opportunities and the project's construction and operation job requirements. As well, Esso plans to continue to assist local business by providing information and discussing opportunities for the supply of goods and services related to the project. Esso believes that its present policies would continue to maximize the Canadian content of its project and provide industrial benefits to Alberta and Canada.

The Board considers the procedures implemented by Esso during the construction of Phases I to IV of the Cold Lake Project to be largely satisfactory and that a continuation of those for Phases V and VI should be acceptable.

5 DECISION

Having reviewed the details of Phases V and VI and having regard for the potential impacts and public benefits, the Board is prepared, with the authorization of the Lieutenant Governor in Council, to approve Phases V and VI as applied for.

DATED at Calgary, Alberta, on 7 May 1985.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Board Member

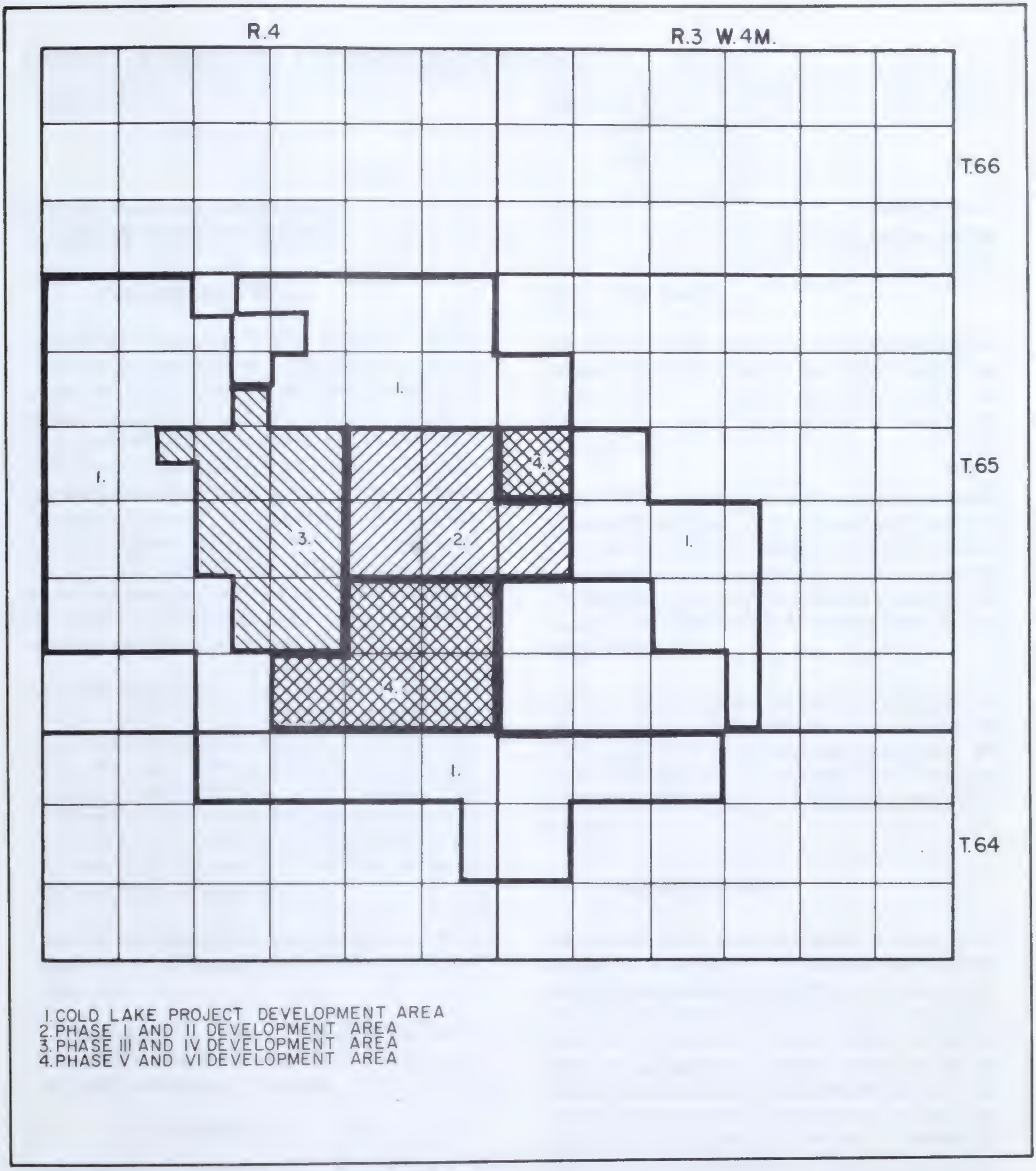


FIGURE 1 COLD LAKE PROJECT DEVELOPMENT AREA.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

CANTERRA ENERGY LTD. BIGORAY NISKU K POOL

Decision D 85-18
Application 831149

1 THE APPLICATION

Canterra filed Application 831149 in December 1983, requesting designation of a special quarter section drilling spacing unit (DSU) comprising the SW/4-10-52-8 W5M for the purpose of removing the off-target penalty factor for the well located at legal subdivision 4-10-52-8 W5M (the 4-10 well). The application was advertised for objection and notice of objection was filed by Amoco Canada Petroleum Company Ltd. (Amoco), Petro-Canada Resources (Petro-Canada), and Texaco Canada Resources Ltd. (Texaco). The application remained in abeyance to allow the concerned parties time to negotiate the matter. In November 1984 Canterra filed an expanded application, requesting the following:

- an order designating a special drilling spacing unit comprising the SW/4-10-52-8 W5M or deeming the 4-10 well to be completed within its target area or that the area of the 4-10 well's drilling spacing unit, contributed to waterflood Project 1, not be reduced by an off-target penalty factor or designating an area of 16 hectares to be allocated to the well located at Lsd 02/16-4-52-8 W5M (the 02/16-4 well) in distributing oil production allowables,
- an order establishing an off-target penalty factor to be applied to the oil production allowable of the 02/16-4 well, and
- an order assigning a reduced maximum rate limitation (MRL) to the 02/16-4 well until enhanced recovery reserves have been recognized.

1.1 The Interventions

Interventions were filed by Amoco, Petro-Canada and Texaco, as working interest owners in the 02/16-4 well, on the basis that their interests would be directly and inequitably affected if Canterra's application was granted. They each requested that the application be denied in its entirety.

Harvard International Resources Ltd. (Harvard), a working interest owner with Canterra in waterflood Project 1, filed an intervention in support of Canterra's application.

1.2 The Hearing

The application was considered at a public hearing in Calgary, Alberta, on 13 and 14 March 1985, with N. A. Strom, P.Eng., C. J. Goodman, P.Eng., and G. A. Warne, P.Eng., sitting. The participants are listed on the following table.

At the commencement of the hearing Amoco presented argument for adjournment of the hearing until Canterra's application and Amoco's waterflood application could be heard concurrently, or indefinitely to allow all parties sufficient time to make a concerted effort to resolve common ownership problems in the Bigoray Nisku K Pool (the K Pool).

Canterra argued that such adjournment would achieve nothing except to further defer or avoid consideration of the merits of its application. After deliberation, the Board ruled that Amoco's proposals were not relevant to the application before it and that the hearing should proceed.

2 BACKGROUND

The area considered in this application is shown on the attached Figure. In March 1979 Amoco drilled and completed the well located at Lsd 00/16-4-52-8 W5M (the 00/16-4 well). The well was drilled within the central target area of the quarter section drilling spacing unit (DSU) in accordance with section 4.020(1) of the Oil and Gas Conservation Regulations (the Regulations). The 00/16-4 well encountered hydrocarbons and was completed in the Nisku formation. The Board subsequently declared the Nisku formation, in the quarter section containing the 00/16-4 well, the Bigoray Nisku J Pool (the J Pool). The 00/16-4 well produced 382.2 cubic metres (m^3) of oil before the Nisku formation was plugged off and the well was recompleted uphole in the Mannville formation.

In September 1980 Canterra drilled and completed a Nisku oil-producing well at Lsd 14-3-52-8 W5M (the 14-3 well). The well was located on-target in the central target area of the DSU. In December 1980 it drilled a

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canterra Energy Ltd. (Canterra) A. L. McLarty	L. E. Fenwick, P.Eng. H. D. Logie, P.Geol. J. Wansleeben, P.Eng.
Amoco Canada Petroleum Company Ltd. (Amoco) S. E. Lipton	J. A. Davis, P.Eng. C. Hojnik, P.Eng. R. Kostash, P.Eng.
Petro-Canada Resources (Petro-Canada) J. Hope-Ross	G. Reitzel, P.Eng.
Texaco Canada Resources Ltd. (Texaco) S. McDougall	R. L. Walker, P.Eng.
Harvard International Resources Ltd. (Harvard) R. L. Bentley	R. L. Bentley
Energy Resources Conservation Board staff R. Hansford T. Hurst R. Willard, P.Eng.	

follow-up well at Lsd 4-10-52-8 W5M for oil production from the Nisku formation. However, the well was drilled off-target relative to the prescribed central target area. The Nisku formation in the two quarter section DSUs containing the 14-3 and 4-10 wells was designated by the Board as the Bigoray Nisku K Pool.

In January 1982 Canterra received ERCB approval to pressure maintain the K Pool, with the 14-3 and 4-10 wells as oil producers and the well located at legal subdivision 12-3-52-8 W5M (the 12-3 well) completed as a water injector.

In January 1983 Texaco drilled a second well in the adjacent J Pool, in the northeast quarter of section 4-52-8 W5M. The well located at Lsd 02/16-4-52-8 W5M encountered hydrocarbons in both the Wolf Lake member and the Zeta Lake member of the Nisku formation and was recognized by the ERCB in its oil allowable administration as an oil producer in the J Pool.

In December 1983 Canterra submitted Application 831149 seeking removal of off-target status for the 4-10 well. Notice of the application was published and objections to removal of the off-target status were received from the working interest owners of the 02/16-4 well. The application was then held in abeyance by the ERCB to allow the concerned parties to pursue alternative means of resolution of the matter. Meanwhile, effective 1 July 1984, the Board ruled that the Bigoray Nisku J and K pools were one pool and designated the coalesced pools as the Bigoray Nisku K Pool. Canterra subsequently requested that Application 831149, filed in an expanded form, be considered by the ERCB since attempts to achieve a resolution of the matter through negotiations apparently were unsuccessful.

3 THE ISSUES

The Board considers the issues with respect to this application to be

- the merits of the proposed change in target area status of the 4-10 well,
- the target area status of the 02/16-4 well,
- the need for a unique resolution of the opposing positions considering the circumstances in the Bigoray Nisku K Pool, and
- the need as a conservation measure to curtail withdrawal rates from the Bigoray Nisku K Pool.

4 THE MERITS OF THE PROPOSED CHANGE IN TARGET AREA STATUS OF THE 4-10 WELL

4.1 Views of the Applicant

Canterra said that the 4-10 well was purposely drilled off-target in an effort to optimize oil recovery from the pool. It considered the alternative of drilling the well within the prescribed central target area to be unsuitable from the viewpoint of maximizing oil recovery, as at that location the well would have encountered only part of the hydrocarbon bearing portion of the reef. Instead, the 4-10 well was located off-target to encounter the reef in its highest position and thus optimize oil recovery with a bottom drive waterflood.

It said that a comparison of pay thickness, permeability, porosity, structural position, and reservoir drive mechanism indicated the 4-10 well would not result in any advantage to Canterra with respect to production of competitively operated wells in the pool.

4.2 Views of the Interveners

Amoco said that any decision declaring the 4-10 well on-target would give Canterra an unfair competitive advantage and that correlative rights would be adversely affected. It expected that removal of the off-target penalty for the 4-10 well would result in higher withdrawal rates from the waterflood project, causing the oil-water interface to migrate upward at a faster rate, resulting in lower ultimate oil production from the 02/16-4 well.

Amoco also observed that it is common practice to locate wells within the prescribed target areas to avoid the application of off-target penalties when adjacent lands are of different mineral ownership. In this respect Canterra should have considered the possibility of an off-target penalty being applied before drilling the 4-10 well in an off-target location.

Petro-Canada and Texaco also claimed that correlative rights would be adversely affected if the 4-10 well was deemed to be on-target and both adopted the basic position of Amoco on this matter.

4.3 Views of the Board

It is clear that the 4-10 well was intentionally drilled outside the prescribed central target area and that Canterra would have been cognizant of an off-target penalty factor being applied if and when another owner completed a producing well in the pool. The Board agrees with the interveners that equity in the pool could be altered if the off-target penalty for the 4-10 well was removed. At the same time, the Board notes that if the 02/16-4 well was to become incapable of production and no other competitively operated wells existed, Canterra could then apply for suspension of the off-target penalty for the 4-10 well. This would allow the 4-10 well to recover oil from the crest of the pool with no off-target production allowable constraints and thereby serve Canterra's objective. In conclusion, the Board does not see any compelling reason to waive or vary the application of the target area regulations in respect to the 4-10 well.

5 TARGET AREA STATUS OF 02/16-4 WELL

5.1 Views of the Applicant

Canterra submitted that the 00/16-4 well was drilled under the existing central target area provision. It further noted that the subsequent 02/16-4 well was drilled in the northeast quadrant only 5 metres from the DSU boundary, and that the well did not properly qualify as an on-target well.

Canterra referred to Board Decision 81-20 which it noted aimed to reduce agricultural land-use impacts by shifting the normal oil well target area to the northeast corner of each quarter section. It observed that the resulting spacing order, SU 1088, provided for the new northeast target requirements to be applicable to all agricultural or semi-agricultural lands (ie, "white" and "yellow" areas of the province) with the exception of those lands in declared oil pools drilled on the existing normal central target areas and those subject to other special oil spacing unit orders. These spacing unit orders provided for other sizes of spacing units or other than central area targets in prescribed areas. The reference date set by the Board for defining the declared oil pools was 1 August 1981. Canterra submitted a copy of Board Order G 3322 to confirm that at 1 August 1981 the Bigoray Nisku J Pool comprised the pool in the Nisku formation in the northeast quarter of section 4-52-8 W5M. Therefore, by Canterra's interpretation of Decision 81-20, any well drilled within the area of the declared J Pool to obtain production from the Nisku formation would be subject to the central target provisions and would not be eligible for northeast target status.

Canterra pointed out that although the Nisku J and K pools were not listed in Appendix A to SU 1088, they were in fact declared oil pools at 1 August 1981. It submitted that the absence of these pools from the list of pools in Appendix A to SU 1088 could not be construed as exempting the J and K pools from the intent of Decision 81-20.

Canterra maintained that ERCB Informational Letter IL 82-4 (IL 82-4), confirmed the intent of Board Decision 81-20; viz that wells drilled after 1 August 1981 in lands within declared oil pools extant on 1 August 1981 would not be eligible for nor subject to the northeast target area requirements of SU 1088. It acknowledged that IL 82-4 also stated that a well to be drilled within the area of such a declared pool, but to obtain production from a potential producing zone not included in that order, would be subject to the new northeast target area provision. However, Canterra's position was that the combination of Board Decision 81-20, Order SU 1088, and IL 82-4, did not contemplate providing more than one target area within a DSU for a potential producing zone. Thus, it maintained that since the 02/16-4 well was drilled within the area of the declared Nisku J Pool to obtain production from the Nisku formation, it was by definition subject to central target provisions. Finally, Canterra stated that the interpretation of the term "different pool" in the exception paragraph in Appendix 1 of IL 82-4 cited by Amoco and other working interest owners of the 02/16-4 well was a very unique interpretation and not in keeping with the context of Decision 81-20 or the intent of SU 1088.

5.2 Views of the Interveners

In addressing the applicability of SU 1088 to the 02/16-4 well, Amoco referred to IL 82-4, which states "that any well drilled within the surface boundaries of a declared oil pool but to obtain production from a different pool, will be subject to SU 1088 spacing requirements". Amoco indicated that the 02/16-4 well was drilled within the surface boundary of the J Pool but to obtain production from the K Pool. Therefore, in its view, the well should be automatically eligible for and subject to the SU 1088 northeast target provisions. It believed that the ERCB issued IL 82-4, Appendix I, having in mind the exact case represented by the adjoining J Pool and K Pool.

Texaco, which drilled the 02/16-4 well, provided three reasons why it deemed the well to be on-target. First, the DSU in which the 02/16-4 well was drilled is located in the white area on Figure 1 to SU 1088. Second, the J Pool in which the 02/16-4 well was located was not listed on Appendix A to SU 1088. Third, and most importantly, the 02/16-4 well was drilled within the surface boundary of the J Pool, but to obtain production from a "different pool", the K Pool.

Petro-Canada supported the positions taken by Amoco and Texaco. It also was concerned that if the 02/16-4 well was now ruled to be off-target, such an interpretation might trigger a series of changes of target areas for lands in other situations similar to those of the J and K pools.

5.3 Views of the Board

The Board notes that the first well in the northeast quarter of section 4-52-8 W5M, the 00/16-4 well, was drilled to the Nisku formation under the existing central target area requirements and its spacing unit, the northeast quarter of section 4-52-8 W5M, was declared the Bigoray Nisku J Pool prior to 1 August 1981.

Pursuant to Decision 81-20, SU 1088 established normal target areas for oil production to be in the northeast quadrant of the quarter section for all agricultural or semi-agricultural lands (ie, "white" and "yellow" land status areas) of the province except those within the boundaries of existing Board-designated oil pools developed on the existing normal central target areas and lands already subject to special spacing unit orders. IL 82-4 elaborated on the implications of the decision with respect to other potential producing zones. In effect the Board decision made provision for conversion to the new northeast target for oil production from all lands in agricultural or semi-agricultural areas except those within the already developed oil pools.

Appendix A to SU 1088, listing most pools which were designated and subject to central target areas, was included to assist prospective developers in identifying lands which would remain on central target areas. However, many small pools for which the designated lands were limited to only one or two DSUs, including the Bigoray Nisku J and K pools, were not listed in the Appendix. The Board believes that it is not reasonable to conclude that the exclusion of these small pools from Appendix A to SU 1088 should be construed as altering the target areas for those pools from their existing central targets to the new northeast targets. Any such construction is in conflict with the intent of Decision 81-20 which was to retain existing target areas in developed oil pools.

Texaco suggested that it intended to complete the 02/16-4 well in a "different pool" than that defined in the G Order for the area and that this qualified the well for the northeast target area provisions. The Board notes, in this respect, that the well was completed within the declared Nisku J Pool as defined by the existing G Order and that the order remained in force from the date of the 02/16-4 well completion in March 1983 until the J Pool was

coalesced with the K Pool on 1 July 1984. In this respect it is clearly evident that the 02/16-4 well was subject to central target provisions during the period March 1983 to June 1984 inclusive, because the 02/16-4 well was classified as a J Pool completion during this period.

What then would be the target status of the northeast quarter of section 4-52-8 W5M after 30 June 1984? The Board is satisfied that coalescing of declared oil pools would not be a valid basis for redefining target area provisions. Indeed, any such practice would lead to continuing changes in target status as pool boundaries were adjusted and would cause widespread uncertainty respecting target status. This would be contrary to the basic tenets of orderly development and would be tantamount to allowing administrative orders to supersede the Regulations.

In summary, the Board rejects the interpretation of IL 82-4 applied by Amoco, Texaco, and Petro-Canada with respect to the 02/16-4 well. The Board concludes that the drilling target area for oil production from the Nisku formation in the northeast quarter of section 4-52-8 W5M is the central target as specified in section 4.020(1) of the Oil and Gas Conservation Regulations.

6 THE NEED FOR A UNIQUE RESOLUTION OF THE OPPOSING POSITIONS CONSIDERING THE CIRCUMSTANCES IN THE BIGORAY NISKU K POOL

6.1 Views of the Applicant

Canterra stated that ordinarily the Board's prime consideration with respect to the target area status of the 02/16-4 and 4-10 wells should be that the provisions of the Regulations are being applied. However, if the Board considered the circumstances in this instance to be so unique as to warrant a special resolution, Canterra proposed, as an alternative, that DSU off-target penalty factors be ignored and that the allowables be distributed in accordance with area weighted by the hydrocarbon pore volume under the DSU. Thus, since approximately 95 per cent of the K Pool hydrocarbon pore volume underlies the waterflood project area, 128 hectares should be assigned to that project, and since only a small amount of hydrocarbon pore volume underlies the primary tract (the 02/16-4 well), the area assigned to it should be only 16 hectares.

6.2 Views of the Interveners

Amoco and the other interveners supported continuation of the practice of distributing allowables among wells within a pool based on DSU area modified by respective off-target penalty factors.

6.3 Views of the Board

While the Board can see some merit in the proposal put forward by Canterra, it views Canterra's suggestion as a proposition that all operators of wells in the pool would have to subscribe to as an equitable and fair formula for sharing of future production. In view of the absence of such agreement, the Board considers application of the provisions of the Regulations, and the allowable administration procedures that derive from them, the fairest method of allowable distribution.

7 THE NEED AS A CONSERVATION MEASURE TO CURTAIL WITHDRAWAL RATES FROM THE BIGORAY NISKU K POOL

7.1 Views of the Applicant

Canterra considered that further delay by the working interest owners of the 02/16-4 well in implementing a scheme to replace voidage resulting from production of the well would have a serious detrimental effect on the efficient depletion of the pool. To at least dampen such effect, Canterra considered it appropriate and necessary to apply a special MRL to the well until such time as it becomes part of a pressure maintenance scheme.

7.2 Views of the Interveners

The interveners did not consider a special MRL for the 02/16-4 well necessary since an application is already before the Board to implement a separate pressure maintenance scheme to replace withdrawals from the well.

7.3 Views of the Board

In view of its previous conclusions and the fact that a pressure maintenance application has been filed, the Board does not consider a special MRL for the 02/16-4 well necessary at this time.

8 DECISION

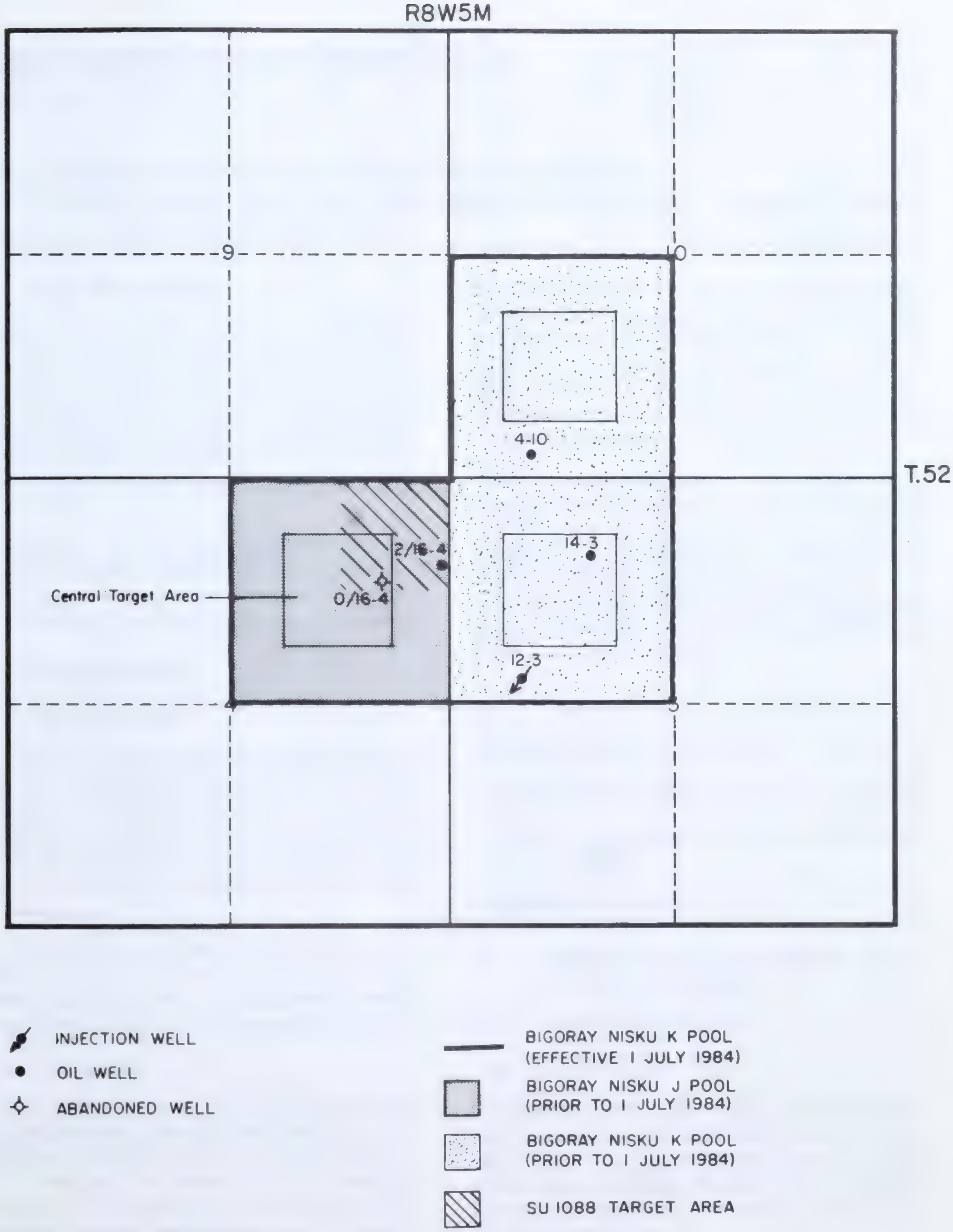
The Board has given due consideration to the evidence respecting the application and interventions and denies each part of Application 831149 filed by Canterra. The Board confirms that the 02/16-4 well and the 4-10 well are both subject to the central target as set out in section 4.020(1) of the Oil and Gas Conservation Regulations, and that effective with the date of this decision, the 02/16-4 well will be subject to the resulting off-target factor determined in accordance with section 4.070 of the Oil and Gas Conservation Regulations.

DATED at Calgary, Alberta, on 9 May 1985.

N. A. Strom, P.Eng.
Board Member

C. J. Goodman
C. J. Goodman, P.Eng.
Board Member

G. A. Warne
G. A. Warne, P.Eng.
Acting Board Member



AREA OF APPLICATION

D85-18
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY CANADIAN OCCIDENTAL PETROLEUM LTD. TO CONSTRUCT SOUR GAS, FUEL GAS, PRODUCED WATER, AND SALES GAS PIPELINE SYSTEMS

Decision 85-19
Applications 850199 to 850204 Inclusive

1 THE APPLICATION

Canadian Occidental Petroleum Ltd. (CanadianOxy) submitted applications to allow it to construct approximately 92 kilometres of 60.3-millimetre (mm) to 219.1-mm outside diameter (OD) pipelines in the Mazeppa area to facilitate the recovery of raw gas for processing through the Mazeppa gas plant, to transport the sweet natural gas for distribution, and to transport produced water to a disposal well.

The application was considered at a public hearing in High River, Alberta, on 16 April 1985, with V. Millard, C. J. Goodman, P.Eng, and R. G. Evans, P.Eng, sitting. Participants at the hearing are listed in the table.

2 INTRODUCTION

2.1 The Interventions

Mr. Broughton requested a pipeline route modification so that it would not traverse the south half of section 22, township 19, range 28, west of the 4th meridian, and interfere with his planned drainage system and future land use. Mr. Broughton also stated a concern about settlement of the backfill and suggested that it be tamped into place.

Mr. Randle expressed concern about the timing of the construction, topsoil conservation, the width of the permanent right of way and the width that would actually be used, construction access and trespassing problems.

2.2 Background

In March 1983, the Board held a public inquiry to consider potential conflicts between development of sour gas reserves and residential development in the Okotoks area, and to investigate how potential conflicts might be minimized. The Board issued Inquiry Report D 83-12 and indicated that there was general agreement by participants that the best means of minimizing that conflict would be by depleting the sour gas reserves as quickly as possible, and deferring further residential development in the area.

In April 1983, the Board held a public hearing in High River to consider an application by CanadianOxy for approval to construct a sour gas processing plant in the Mazeppa area. In Decision D 83-13 the Board stated it believed that the proposed plant would be in the public interest and its approval would support the general objectives cited in the Board's Inquiry Report D 83-12. The application for the sour gas processing plant was subsequently approved by the Board.

The Mazeppa gas plant is designed to accommodate all sour gas production in the Okotoks area which is not currently being produced, or which is not reasonably capable of being produced, to the existing Canterra Okotoks gas plant. The proposed pipeline system is, consequently, an integral and essential part of the Mazeppa gas processing project to expedite depletion of the sour gas reserves in the Okotoks area.

3 THE ISSUES

The Board considers the issues to be

- Design, safety equipment and operating procedures
- Pipeline routing through S-1/2 22-19-28 W4M (Mr. Broughton's land)
- Construction practices

4 DESIGN, SAFETY EQUIPMENT, AND OPERATING PROCEDURES

4.1 Well 11-17-20-28 W4M

4.1.1 CanadianOxy's Views

CanadianOxy stated that the well at 11-17-20-28 W4M (11-17 well) is presently connected to and will remain producing into the Canterra Okotoks system, but that it is considering producing this well into the Mazeppa system in the future. The 11-17 well will produce into only one system at any time.

4.1.2 Board's View

The Board recognizes that the applicant's plans respecting the 11-17 well are not finalized and the applied-for sour gas and fuel gas pipelines to it might or might not be required, depending on the decision as to where the

gas from the well will be processed. None of the interveners commented on that portion of the application. Under these circumstances the Board is prepared to accept for an interim period that there may be a need for the applied-for pipelines. However, if construction does not proceed within 3 months of the time the Mazeppa plant is placed on production, or the applicant does not advise that it plans construction, the Board will conclude that a need does not exist and any permit issued would be cancelled.

4.2 Electromagnetic Inspection Capability

4.2.1 CanadianOxy's Views

CanadianOxy stated that the sour gas gathering lines have not been designed to accommodate an internal electromagnetic inspection tool. The proposed corrosion monitoring techniques such as corrosometers, removable inspection spools, corrosion coupons, and ultrasonic readings would provide equivalent information to that obtained by internal electromagnetic inspection. The proposed corrosion monitoring techniques will be deployed at locations based on past experience, generally at pipeline junctions.

CanadianOxy indicated that, although the incremental cost to modify the design to accommodate an internal electromagnetic inspection tool would be insignificant, the pipeline pressures will be insufficient within 2 years to drive the sensing device through the pipe.

4.2.2 Board's Views

None of the interveners commented on this, but the Board believes that modern, sour gas pipelines in populated areas should be designed for internal electromagnetic inspection capability. However, the Board understands that electromagnetic inspection tools for pipelines smaller than 88.9 mm OD have not yet been developed. Since the applicant confirmed that the incremental cost of design modifications to accommodate an internal electromagnetic inspection tool would be relatively insignificant, the Board will require the sour gas pipelines greater than 88.9 mm OD, as listed in CanadianOxy Applications 850199 and 850200, to be designed and constructed with internal electromagnetic inspection capability.

The Board sees the advantages of an internal electromagnetic inspection over the use of other corrosion monitoring techniques. However, it will not immediately require that an internal inspection be carried out. Should a permit be granted, the Board will condition it to require CanadianOxy to submit a report which discusses the feasibility of running an internal electromagnetic inspection tool. The report shall address the advantages and disadvantages of the internal electromagnetic inspection technique as it relates to the Mazeppa system, and the alternative drive methods available on the system.

The Board is satisfied that the pipeline is generally adequately designed.

4.3 Emergency Response Plan

4.3.1 CanadianOxy's Views

CanadianOxy stated it had submitted a draft emergency response plan for the total Mazeppa project, including the plant, the pipelines, and the wells to the Board. Copies of the draft plan were available at the open house held at Alderside on 3 April 1985. Comments regarding the plan were invited by providing a stamped self-addressed envelope with the document. It indicated the emergency response plan cannot be completed until the drilling program is completed, since information regarding well characteristics will influence the emergency planning. CanadianOxy expects the program to be completed by late fall of 1985.

4.3.2 Board's Views

The Board appreciates the difficulty in finalizing the emergency response plan prior to the completion of the drilling program.

The Board notes that none of the interveners commented on this but, due to the proximity of populated areas, the Board will require the approved emergency response plan to be in place prior to filling of the pipelines with sour gas.

5 PIPELINE ROUTING THROUGH MR. BROUGHTON'S LAND

5.1 CanadianOxy's Views

CanadianOxy indicated that the route modifications suggested by Mr. Broughton through S 1/2 22-19-28 W4M would result in a longer length of pipeline being installed in very good quality land. As an alternative, CanadianOxy agreed to install the pipelines at a greater depth as necessary to avoid interference with Mr. Broughton's drainage system, and at no cost to Mr. Broughton.

5.2 Intervener's Views

Mr. Broughton suggested a modification to the pipeline routing so that it would not traverse S 1/2 22-19-28 W4M, and thereby not interfere with his planned drainage system and the optimization of future land use. He agreed that the suggested route modification would increase the length of the pipeline and that it would be installed in better quality land.

After discussion with the applicant, Mr. Broughton consented that the drainage system could co-exist with the applied-for pipeline routing, provided that it was installed at sufficient depth to cause no interference with his planned drainage scheme. He agreed to accommodate extra work space to permit the increased depth of pipeline.

5.3 Board's Views

The Board notes that the applicant and Mr. Broughton agreed on a solution to the problem of Mr. Broughton's drainage system and therefore considers the issue to be resolved. In any case, the Board believes that the proposed route, with deeper burial depth, is preferable in view of the additional land disturbance resulting from the modified route.

6 CONSTRUCTION PRACTICES

6.1 Construction Schedule

6.1.1 CanadianOxy's Views

CanadianOxy stated if approval is received by early June, the planned start of construction of the pipelines is mid September with completion by late November. This would minimize the interference with farming operations, but permit completion of the construction prior to freeze-up.

CanadianOxy also indicated that, provided prompt approval was obtained, summer construction would be possible, and in fact it would prefer it, if there was no objection from landowners.

6.1.2 Interveners' Views

Mr. Randle opposed late fall and winter construction, and believes a satisfactory job cannot be performed after freeze-up.

Both Mr. Randle and Mr. Broughton agreed that summer construction would be preferred since construction and clean-up would be completed in one season, results of backfilling operations would probably be improved, and there would be less potential for topsoil damage.

6.1.3 Board's Views

The Board concurs with the views of CanadianOxy, Mr. Randle, and Mr. Broughton, and their preference for pipeline construction during summer. Provided CanadianOxy can obtain the consent of the landowners, the Board agrees to summer construction.

6.2 Topsoil Conservation

6.2.1 CanadianOxy's Views

Based on field evaluation, CanadianOxy compiled a drawing showing the depth of topsoil along the proposed easement, and this drawing will be referred to during the topsoil stripping operation. Normal maximum topsoil stripping depth will be 30 centimetres (cm). However, in isolated areas and where justified, increased depth of topsoil would be stripped. CanadianOxy indicated preference for stripping topsoil by grader, but conceded that a bulldozer may be used under certain circumstances. There will be at least one qualified inspector of the topsoil stripping operation whose primary responsibility will be environmental concerns and who will have considerable experience with pipeline construction. CanadianOxy admitted that topsoil stripping, particularly if two construction spreads are utilized, could occur without continuous supervision. Should there be more than one topsoil stripping operation, CanadianOxy undertook to retain an additional qualified inspector or to consult with each landowner to establish the required depth of topsoil stripping.

6.2.2 Interveners' Views

Mr. Randle expressed concern that the full depth of topsoil would not be conserved in all areas and requested full depth of topsoil to be stripped in areas such as fencelines and edges of fields where the depth of topsoil could be considerably more than 30 cm.

Mr. Broughton requested that he be consulted by CanadianOxy regarding soil preservation on his land.

6.2.3 Board's View

Topsoil conservation is essential and the Board will require a qualified inspector present at each stripping operation to determine the proper depth of topsoil stripping, and to ensure that saline subsoil is not stripped. The Board expects consultation with the individual landowners prior to topsoil stripping on their lands.

6.3 Backfilling Practice

6.3.1 CanadianOxy's Views

CanadianOxy considers the normal practice of crowning over the ditchline sufficient to compensate for eventual settlement of the backfilled trench. It indicated that it could be hazardous to the pipe to tamp the backfill in a partially backfilled pipeline ditch.

6.3.2 Intervener's Views

Mr. Broughton suggested tamping of the bottom 60 cm of the backfill to minimize the settlement of the backfill material. Mr. Broughton indicated that the extent of settlement also depends on the moisture content of the backfill material and suggested summer construction would probably alleviate settlement problems, since soils generally have lower moisture content and are thus more friable.

6.3.3 Board's Views

The Board considers that there may be a potential hazard to the pipeline due to tamping of trench backfill and will not require tamping of partially backfilled pipe ditches. Summer construction with proper crowning of the trench should minimize noticeable unevenness by the next seeding season. Nevertheless, CanadianOxy will be responsible for recontouring any areas where subsequent settlement occurs.

6.4 Temporary Working Space and Permanent Right of Way Width

6.4.1 CanadianOxy's Views

CanadianOxy stated that the width of the permanent right of way will be 15 metres (m) and the general width of extra working space will be 5 m. Additional working space will be required in locations of multiple pipelines and 15 to 20 m of extra working space may be required at road and railway crossings. Extra working space is required only for the duration of construction. The 15-m permanent right of way is sufficient for operation and maintenance of the pipeline system.

6.4.2 Intervener's Views

Mr. Randle questioned the sufficiency of the width of the permanent right of way for operation and maintenance of the pipeline system. Mr. Randle believes the 15-m wide permanent right of way is insufficient and expressed concern regarding frequency of off right of way trespassing during future operation of the system.

6.4.3 Board's Views

The Board views the 15-m permanent right of way width to be acceptable for the future operation and maintenance of the pipeline system. The Board recognizes the need for variability of extra work space width which is dependent on various conditions, including the number of pipelines, the types of soils, and the difficulty of road or railway crossings.

6.5 Access

6.5.1 CanadianOxy's Views

CanadianOxy stated that it will minimize travel along the easements and use public roads and farm access roads where feasible. It confirmed that it will implement dust control measures wherever it is reasonably possible to do so. CanadianOxy stated that compaction along the easement, resulting from the construction activity, will be rectified by disking.

6.5.2 Intervener's Views

Mr. Randle supported minimization of travel along the easement and encouraged the utilization of farm access roads. He expressed concern about increase in trespassing by the public caused by new access and requested that any public access resulting from the pipeline construction be removed at the conclusion of construction.

6.5.3 Board's Views

The Board expects CanadianOxy to take proper steps to utilize existing access to the greatest degree possible.

7 DECISION

The Board is prepared to issue the appropriate pipeline construction permits to CanadianOxy for the applied-for sour gas lines, water injection lines, fuel gas lines, and sales gas lines, in the route shown on drawing MAZ-178-R2.

The pipeline permits will have the following conditions attached:

(1) If the construction of the pipelines to the 11-17 well does not proceed within 3 months of the commencement of plant operation, they will expire unless the Board has advised in writing to the contrary.

(2) The sour gas pipelines greater than 88.9 mm OD as listed in CanadianOxy Applications 850199 and 850200 shall be designed for internal electromagnetic inspection capability.

(3) CanadianOxy shall submit a report for sour gas pipelines greater than 88.9 mm OD. The report shall discuss the feasibility of running an internal electromagnetic inspection tool and shall address the advantages and disadvantages of the internal electromagnetic inspection technique as it relates to the Mazeppa system and the alternative drive methods available. This report shall be submitted to the Board prior to completion of construction.

(4) The permittee shall complete its emergency response plan in a manner satisfactory to the Board prior to filling of the pipelines with sour gas.

(5) The permittee shall ensure that the pipeline installation will not interfere with the planned drainage system in S 1/2 22-19-28 W4M.

(6) The permittee shall ensure that a qualified inspector is present at each topsoil stripping operation.

The Pipeline permits will be issued subject to the above conditions and receipt of the approval of the Minister of the Environment respecting environmental matters as set out in section 8 of the Pipeline Act.

ISSUED at Calgary, Alberta, on 8 May 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

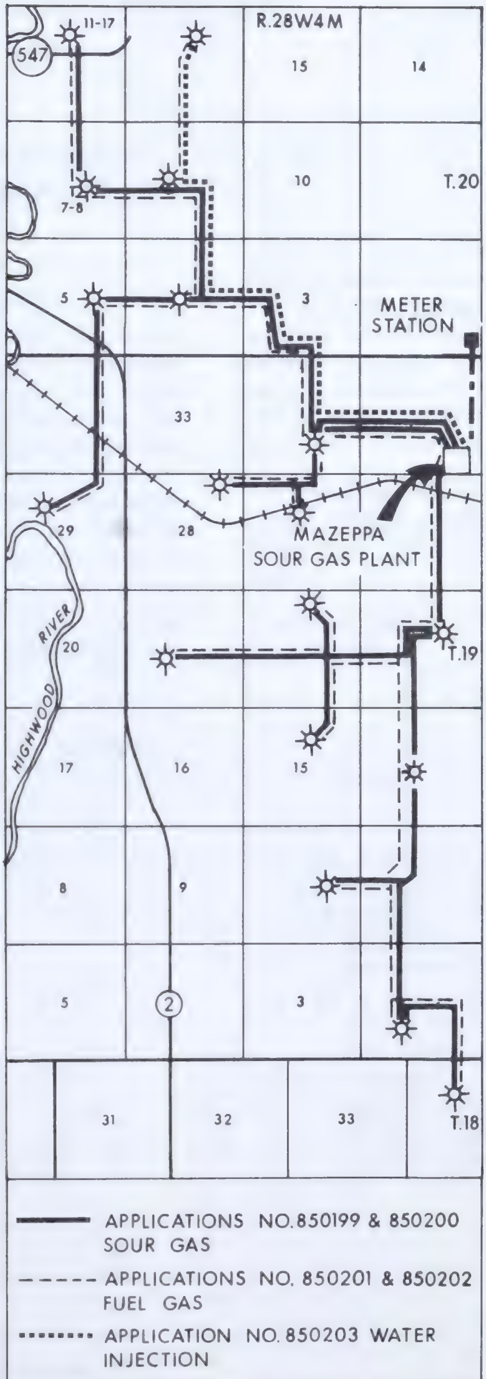
R. G. Evans

R. G. Evans, P.Eng.
Acting Board Member

APPENDIX

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Canadian Occidental Petroleum Ltd. (CanadianOxy) A. L. McLarty	D. L. Johnson of Hardy Associates (1978) Ltd. E. S. Yagos, P.Eng. T. R. Fountain, P.Eng. A. D. Cocks
Randle Farms Ltd. Fred Randle Farms Ltd. Patricia M. Randle F. E. Randle	F. E. Randle
O. J. Broughton	O. J. Broughton
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff A. Gervais A. Cassley, P.Eng. N. Harris, P.Eng. T. J. Pesta, P.Eng.	



CANADIAN OCCIDENTAL PETROLEUM LTD.
MAZEPPA AREA
APPLICATIONS NO. 850199 - 850204

D 85-19
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ALTANA EXPLORATION COMPANY CAROLINE GAS PROCESSING PLANT

Decision D 85-20
Application 841218

1 INTRODUCTION

1.1 The Application and Hearing

Altana Exploration Company (Altana) applied for approval to increase the maximum sulphur inlet rate at its gas plant located in legal subdivision 12 of section 36, township 34, range 6, west of the 5th meridian (12-36) in the Caroline Field. The applicant proposed that Board Approval 3616 be amended to reflect an increase in the hydrogen sulphide (H_2S) content of gas from Altana's well in Lsd 6-29-34-5 W5M (6-29), the only well that currently produces sour feed gas to the plant.

The proposed increase in the facility's H_2S inlet rate would not require any change to the present plant process or design; however, the maximum sulphur dioxide (SO_2) emission rate would increase to 7.32 tonnes per day (t/d) (3.66 t/d equivalent sulphur) from the currently approved emission rate of 1.64 t/d SO_2 (0.82 t/d equivalent sulphur). The presently approved maximum raw gas inlet rate of 366 thousand cubic metres per day (10^3 m^3/d) of plant feedstock (raw gas and condensate) would remain unchanged.

The application was considered at a public hearing in Caroline, Alberta, on 9 April 1985, with G. J. DeSorcy, P.Eng., H. J. Webber, P.Eng., and J. A. Bray, P.Eng., sitting.

Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Altana Exploration Company (Altana) F. M. Saville, Q.C. R. A. Neufeld	M. D. Bishop, P.Eng. H. Schlieman, P.Eng. W. Chapman, P.Ag. of McKinnon, Allen & Associates (Western) Ltd. W. R. Hartt, P.Eng. of Duckworth, Price, Henderson & Associates Ltd. M. Schroeder of Western Research, Division of Bow Valley Resource Services Ltd.
Dome Petroleum Limited (Dome) K. F. Miller	
Alberta Environment C. S. Liu, P.Eng.	
Energy Resources Conservation Board staff C.J.C. Page M. Semchuck, C.E.T. D. K. Pippard	

Although Dome was present it did not cross-examine the applicant or present evidence or argument.

1.2 Background

Board Approval 3616 for Altana's Caroline gas plant, issued in August 1982, limits the plant inlet capacity to 366 x 10^3 m^3/d of raw gas containing not more than 592 m^3/d of H_2S. SO_2 emissions are thereby limited to a maximum of 1.64 t/d. The plant has no sulphur recovery facilities. The 6-29 well, which produces the sour gas, is the only well presently capable of producing from the Elkton A Pool.

2 ISSUES

The Board considers the issues regarding the application to be:

- the need to increase the currently approved H_2S inlet rate,
- ambient air quality and sulphur deposition, and
- Altana's proposed further development in the Caroline Field.

3 NEED TO INCREASE THE APPROVED H_2S INLET RATE

Altana stated that it required an approval to increase the H_2S inlet and SO_2 emission rates at the Caroline gas plant because the H_2S concentration of the raw gas produced from the 6-29 well has increased over time. The applicant believes H_2S is increasing for reasons related to an advance of the gas/water interface as the reserves are produced. The 6-29 well's raw gas presently has an H_2S concentration of approximately 1.25 per cent but the applicant believes that the H_2S concentration may increase to a maximum of 1.37 per cent.

Altana indicated that in applying for a maximum H_2S inlet rate of 2700 m^3/d, it wanted to ensure that its Caroline plant had approval to process the 6-29 well's raw gas at worst-case conditions of H_2S concentration (ie, 366 x 10^3 m^3/d raw gas with an H_2S concentration of 1.37 per cent). Altana claimed that the plant's presently approved sulphur inlet rate of 592 m^3/d of H_2S prevents the applicant from producing the 6-29 well at its maximum capability, especially during periods when sales gas contracts would allow for high production rates. It further claimed that the applied-for sulphur inlet rate would allow Altana to produce its 6-29 well at greater flow rates and thereby fulfil its gas sales contract obligations.

The Board notes that the applicant has obtained the rights to the gas reserves, it has drilled and completed wells capable of producing gas, and is legally entitled to produce the gas in the Caroline Field. The Board believes that in designing the 12-36 gas plant initially, Altana could not have been expected to anticipate or provide for the possibility of the 6-29 well's gas increasing in H_2S concentration over time. Consequently, the Board recognizes that Altana must seek approval to operate its gas plant at a higher H_2S inlet rate if it is to process enough gas from the 6-29 well in the Caroline Field to meet its sales gas contract commitments.

The Board concludes that the applicant has the right to produce its gas reserves subject to compliance with the pertinent regulations, standards, and guidelines and approvals, and if in the future, Altana wished to further increase the 12-36 plant's H_2S inlet rate for any reason, the matter would be the subject of a new application. The Board further concludes that it would be appropriate to increase the H_2S inlet rate to the plant, as applied for, provided concentrations of SO_2 in the ambient air and sulphur deposition levels in the area would be acceptable.

4 AMBIENT AIR QUALITY AND SULPHUR DEPOSITION

Altana used a computer model to study the effects that the emissions of SO_2, at both the existing and applied-for levels, would have on air quality in the area. The applicant outlined that its study took into account regional sulphur emissions which included the flare stack emissions from the Dome North Caroline and Citadel Caroline gas plants, and the incinerator stack emissions from the Dome South Caroline gas plant.

Altana said its modelling accounted for the conditions of plume dispersion under adverse meteorological conditions, and the most adverse possible overlapping from the area plants, that being the subject plant and the Dome North Caroline gas plant which is situated 2.6 kilometres (km) to the north-northwest. Under these conditions, Alberta Environment's 1-hour average air quality objective of 0.17 parts per million (ppm) SO_2 concentrations would be exceeded about 8 hours per year if the plant's existing 30.5-metre (m) high flare stack was utilized to disperse the applied-for increased SO_2 emissions and if both plants were emitting maximum permitted amounts of SO_2.

Altana stated that if a 45.7-m high flare stack was utilized, an overall maximum 1-hour average SO_2 concentration of 0.163 ppm would result, in compliance with Alberta Environment's current air quality objectives.

Altana also indicated it had determined the sulphur deposition rates in the area of its 12-36 gas plant; its estimate was obtained using Alberta Environment's SULDEP sulphur deposition model. The determinations of deposition assumed that all four SO_2 emitting plants

in the area would emit at their maximum permissible rates all year.

The applicant stated that, with the existing 30.5-m flare stack, the maximum annual sulphate deposition would be 46.2 kilograms (kg) per hectare, and this would occur in a 25- to 40-hectare area some 2 km southeast of the 12-36 plant. Altana verified that with a 45.7-m flare stack, maximum annual sulphate deposition would be 39.3 kg per hectare, and this would occur in the same downwind surface area southeast of the subject plant.

Altana outlined that the maximum desirable level for wet sulphate deposition that was recently agreed upon by federal and provincial environment ministers was 20 kg per hectare per year. This target level has been suggested as being protective of all of the environment with the exception of the most sensitive aquatic environments. The applicant further outlined that measured values of wet and dry sulphur deposition have been found to be on the same order of magnitude, and the target level of 20 kg per hectare per year for wet sulphate corresponds to a total sulphate deposition (wet plus dry) of about 40 kg per hectare per year.

The Board accepts Altana's evidence regarding its air quality assessment and its projected sulphur deposition rates but recognizes that actual sulphur deposition may vary somewhat from the applicant's predictions.

In summary, having regard for the air quality standard, the evidence indicates that the 45.7-m stack would be acceptable, and the 30.5-m stack would be acceptable except possibly for about 8 hours per year if both the Altana and Dome plants were emitting SO_2 at their maximum approved rates. Similarly, the guideline for annual sulphur deposition would be met if a 45.7-m stack were used, but could be exceeded somewhat in a small area if the existing 30.5-m stack were used and all plants emitted steadily at maximum approved rates.

5 ALTANA'S PROPOSED FURTHER DEVELOPMENT IN THE CAROLINE FIELD

Altana stated that although the use of its existing 30.5-m flare stack would not ensure compliance with Alberta Environment's objective of the maximum ground level concentration of 0.17 ppm SO_2 on an hourly average at all times, it did not wish to increase the height of its flare stack at this time. Altana stated that there likely are additional sour gas reserves in the area of its plant and if developed, such successfully proven sour gas reserves may warrant the installation of sulphur recovery facilities at the 12-36 gas plant.

Altana stated that it intends to initiate exploration and development activity in the Caroline Field in May 1985. Under its program it would:

- conduct a seismic program with the interpretation of the geophysical information to be completed by the beginning of July 1985;
- identify potential drilling locations by the middle of July 1985;
- commence drilling the first additional well by the beginning of January 1986; and
- if Altana's proposed drilling program in the Caroline Field results in the establishment of 700 million cubic metres of hydrogen sulphide bearing recoverable gas, the applicant would consider modifying the existing 12-36 gas plant and applying to the Board for approval to install and operate a sulphur recovery unit at the Altana Caroline gas plant.

The applicant stated that in light of its proposed development in the area, it would prefer to defer investing capital in a higher flare stack with the hope that it would develop the additional sour gas reserves that would be required to make the installation of sulphur recovery facilities at the subject plant economic.

The Board notes Altana's commitment to an exploration and development program in the Caroline Field and concurs with the applicant that the funds which might be used to construct a higher flare stack would be better spent towards installing properly sized sulphur recovery and related facilities in 24 months' time in the event that Altana's proposed development program is successful. Although it is possible that the 45.7-m flare stack might adequately serve the plant if it were expanded, it seems more probable that a stack of different height or diameter would be needed. The Board further notes that the likelihood is very small that both the Altana and Dome North Caroline plants would emit SO_2 at maximum rates during the few hours per year when conditions would otherwise result in a slight exceedance of the Alberta standard for SO_2 concentration in the ambient air. Similarly, the sulphur deposition guideline would likely be met, having regard for fluctuations in throughputs and emissions at the area plants. The Board thus concludes that it would be appropriate to approve the application and allow interim use of the existing 30.5-m flare stack provided there are adequate checks to review the progress of the exploration and development program and a provision for review when that program is completed or halted.

6 DECISION

Having considered the evidence, the Board is prepared to approve Altana's application to increase the H_2S inlet rate to its Caroline plant to 2700 m^3/d and to continue to use the existing 30.5-m flare stack for emitting SO_2 subject to the following:

- Altana shall report to the Board at 6-month intervals on the progress of its exploration and development program to develop additional gas reserves in the vicinity of the plant, the first report to be submitted by 30 June 1985;
- assuming continuance of the program, Altana shall apply to the Board by 1 May 1987, or such other date as the Board may stipulate, for appropriate amendment of Approval 3616 for installation of sulphur recovery facilities, flare stack modification, reduction in H_2S inlet rate, or such other amendment as may be appropriate; and
- in the event that the Board is of the view that the plant emissions of SO_2 are causing violations of the air quality standard, that additional sour gas reserves will not be developed at an appropriate pace, or that Altana has not complied with the immediately preceding requirements, the Board will stipulate a lesser maximum H_2S inlet rate or undertake a reconsideration of Approval 3616.

The Board's approval of the application is subject to receipt of the approval of the Minister of the Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 21 May 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

H. J. Webber, P.Eng.
Acting Board Member

J. A. Bray, P.Eng.
Acting Board Member

ERCB

Electric Generation Expansion 1986-1991
Sheerness And Genesee Power Plants

Report to the Lieutenant Governor in Council

With respect to an Energy Resources Conservation Board proceeding to amend Approval HE 8312 held by Alberta Power Limited and TransAlta Utilities Corporation and Approval HE 8320 held by The City of Edmonton.

May 1985

ENERGY RESOURCES CONSERVATION BOARD
DECISION REPORT SERIES

Also in this series

79-AA	and Addendum: Alberta Power Limited Forestburg Collieries – Manalta Coal Sheerness Mine and Power Plant – and Edmonton Power – Genesee Power Plant and Coal Mine – Decision Report
80-B	Calgary Power Ltd. Keephills Power Plant Expansion – Decision Report
82-C	Generation Expansion 1985-1987 Keephills and Genesee Power Plants – Decision Report
D 83-H	Electric Generation Expansion 1985-1990 Sheerness and Genesee Power Plants – Decision Report

Report D 85-21 concerns

Proceeding 840837 initiated by the Energy Resources Conservation Board to review the commissioning dates of the Sheerness and Genesee generating units in the 1986-1991 period in light of events which occurred after the issuance of Decision Report D 83-H.

Published May 1985 by:

Energy Resources Conservation Board
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Calgary, Alberta
T2P 3G4

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TABLES AND FIGURES

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TABLES

FIGURES

1 BACKGROUND TO THE PROCEEDING AND HEARING

In the late 1970s the Board approved the construction of three new thermal electric plants in the province: Keephills, Sheerness, and Genesee. The Board's decisions were made in the public interest and based on the best available evidence at that time.

Two generating units have since been commissioned at the Keephills site, in 1983 and 1984, and construction of the Sheerness and Genesee plants is underway. One generating unit at Sheerness is almost completed and could start commercial operation as early as January 1986. The first unit at Genesee is under construction and could be completed in 1988. The remaining units at Sheerness and Genesee are in various stages of manufacture, delivery, and construction.

Since the initial approvals of the Sheerness and Genesee plants, conditions have drastically changed and the commissioning dates of the Sheerness and Genesee generating units have been the subject of two applications to the Board. The Board's decisions respecting these applications are contained in Decision Reports 82-C and D 83-H.

1.1 The Proceeding

This report discusses the Energy Resources Conservation Board proceeding to review the commissioning dates of the generating units in the Sheerness and Genesee power plants, as described in Approvals HE 8312 and HE 8320 respectively. The review arose out of the Board's December 1983 Decision Report D 83-H on the deferral of the Sheerness and Genesee power plants. In that report, the Board made certain observations regarding the risk that further erosion of load growth might require another review to defer the units from the dates specified in 1983. It requested the utilities to report back to it by the end of 1984 on optimization of the commissioning dates of the units, and stated that it expected further review would confirm if further action would be necessary.

In July 1984, the Electric Utility Planning Council (EUPC) issued an updated forecast which indicated significant expected decreases in future load growth rates to the year 2009. In August 1984, TransAlta Utilities Corporation (TransAlta) and Alberta Power Limited (Alberta Power) re-examined the timing of the Sheerness and Genesee units in light of the updated forecast and submitted a letter to the Board requesting a public hearing on the continuing construction of the power plants.

In September 1984, the Board called a public prehearing meeting to obtain the views of all parties who might be interested in the Sheerness and Genesee power projects. Based on the views expressed by the participants at that meeting, the Board decided to call a public hearing to consider appropriate commissioning dates for the Sheerness and Genesee generating units.

In October 1984, Board staff convened a meeting of all interested parties to discuss such matters as: the economic parameters to be used in the costs and benefits analyses, the detail of the information and any supporting evidence to be provided at the hearing, and the format of presentation. As a result of that meeting, Alberta Power, The City of Edmonton (Edmonton Power), and TransAlta prepared an information package of technical and economic data relating to the evaluation of thirteen sequences of generating unit additions. That package, referred to as the "Technical Information Package", was submitted jointly by the utilities to the hearing.

1.2 The Hearing: Participants

A public hearing to consider appropriate commissioning dates for the Sheerness and Genesee generating units was held in Edmonton during 22-25 January 1985 and on 30 January 1985, with V. Millard, C. J. Goodman, P.Eng., and F. J. Mink, P.Eng., sitting. Those who appeared at the hearing are listed in Table 1.

1.3 Summary of Suggested Expansion Sequences

At the hearing, the participants supported various generation sequences evaluated in the Technical Information Package and suggested that they be considered by the Board. Edmonton Power suggested an additional sequence which is a variation of sequence 9 of the Technical Information Package. All of the suggested sequences are shown in Table 2.

2 VIEWS OF THE PARTICIPANTS

2.1 The Electric Utility Planning Council

The EUPC presented its 1984 forecast of electric energy requirements to the year 2009. It concluded that none of the generating units in question would be required by their currently-approved commissioning dates to reliably meet this forecast, and identified the latest possible dates by which each unit would be required. The new sequence of latest possible dates was termed the maximum-deferral sequence (Sequence 3 in Table 2). The EUPC also provided estimates of the lifetime costs and revenue requirements associated with both the currently-approved sequence and the maximum-deferral case. The EUPC did not take a position with respect to the desirability of any particular sequence.

2.2 Alberta Power Limited

Alberta Power agreed that the Sheerness and Genesee units are not required by their currently-approved

TABLE 1 PARTICIPANTS AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Electric Utility Planning Council (EUPC) E. O. McAvity	G. Hanslip, P.Eng. of The City of Calgary J. Gunn, P.Eng. of Alberta Power W. Taylor and R. Valiant, P.Eng. of TransAlta
Alberta Power Limited (Alberta Power) J. C. Major, Q.C.	K. Provost, P.Eng. J. R. Frey, P.Eng. G. Lake, P.Eng.
TransAlta Utilities Corporation (TransAlta) M. H. Patterson, Q.C. W. G. Hopkins	W. L. Fraser, P.Eng. T. Crowe, P.Eng.
The City of Edmonton (Edmonton Power) J. W. Beames, Q.C. M. Sherk	E. F. Kyte, P.Eng. A. Pettican, P.Eng. R. Wright of Wright Mansell Research Ltd.
The City of Calgary (Calgary) R. F. Goss D. A. Larder	
The City of Lethbridge (Lethbridge) Alderman E. Martin	E. Martin
Industrial Power Consumers Association of Alberta (IPCAA) R. Curtis	B. W. Clark, C.A.
Fording Coal Limited (Fording) J. R. Smith, Q.C.	
Manalta Coal Limited (Manalta) D. A. Holgate	L. Portigal J. Decker, P.Eng. R. Shaneman
Luscar Limited (Luscar) M. MacDonald	D. Smith, P.Eng. K. Haddock, P.Eng.
Electrical Contractors Association of Alberta (ECAA) G. A. Soucy	G. A. Soucy
Energy and Chemical Workers Union R. Nielsen	R. Nielsen E. Coe
Southern Alberta Building and Construction Trades (Southern Alberta) P.R.J. Pittman	J. Briegel
Alberta & N.W.T. (District of (MacKenzie) Building & Construction Trades Council R. Garby	R. Garby J. Briegel
INTEG – Intercontinental Engineering Ltd. M. J. Smith, P.Eng.	M. J. Smith, P.Eng.

TABLE 1 (continued)

Principals and Representatives (Abbreviations used in Report)	**Witnesses**
Cana Construction Co. Ltd. J. D. Dunlop, P.Eng.	J. D. Dunlop, P.Eng.
The County of Leduc No. 25 E. J. Walter, Q.C.	K. Pinkowski
The Town of Hanna and District A. L. McLarty	S. Dookie A. Grover
The Town of Calmar G. McCartney	G. McCartney
The Village of Warburg D. Haggerty	D. Haggerty
The Village of Thorsby L. Bacsik	B. Senio
The Village of Breton J. D. Hilker	J. D. Hilker
Edmonton Economic Development Authority A. G. Bleiken	A. G. Bleiken
Battle River Regional Planning Commission G. Scerbak	G. Scerbak
Palliser Regional Planning Commission P. D. Fenwick	P. D. Fenwick
Alberta Wind Power Associates J. Otis	
Energy Resources Conservation Board staff (ERCB staff or Board staff) C.J.C. Page M. L. Asgar-Deen, P.Eng. F. Rahnama A. Kwaczek P. Wickel	

The City of Red Deer, The Alberta Union of Rural Electrification Associations, Stuart Olson Construction Ltd., Hanna and District Chamber of Commerce, Edmonton Chamber of Commerce, and William Arsene filed submissions but did not appear at the hearing.

The City of Calgary, Fording Coal Limited, and Alberta Wind Power Associates registered and participated at the hearing but submitted no direct evidence.

TABLE 2 SUMMARY OF SUGGESTED EXPANSION SEQUENCES

SEQUENCE NO.	1986	1987	1988	1989	1990	1991
1	BC/01,S1/01	S2/07	G2/06	G1/02	-	-
2	BC/01,S1/01	-	-	-	S2/07,G2/10	G1/10
3	BC/01	-	-	S1/10	S2/07,G2/10	G1/10
4	-	BC/09	G2/01	-	S1/07,G1/10	S2/10
5	-	G2/10	-	BC/09	S1/07,G1/10	S2/10
6	-	BC/09	G2/01	-	S1/07,S2/10	G1/10
7	S1/01	-	-	BC/09	S2/07,G2/10	G1/10
8	-	BC/09	-	S1/10	S2/07,G2/10	G1/10
9	S1/01	-	G2/01	S2/10	BC/09	G1/10
*9a	BC/01,S1/01	-	G2/01	S2/10	-	G1/10
10	S1/01	-	S2/01	G2/10	BC/09	G1/10
11	-	BC/09	S1/01	-	S2/07,G2/10	G1/10
12	-	S1/10	-	BC/09	S2/07,G2/10	G1/10
13	BC/01,S1/01	-	S2/01	G2/06	G1/02	-

NOTES:

1. BC/mm – B.C. Tie/commissioning month
   S1/mm – Sheerness 1/commissioning month
   S2/mm – Sheerness 2/commissioning month
   G2/mm – Genesee 2/commissioning month
   G1/mm – Genesee 1/commissioning month

2. Sequence No. 1 represents the currently-approved addition of generating units to the Alberta interconnected system.

* This sequence was not contained in the Technical Information Package. Information relating to this sequence was submitted by Edmonton Power at the hearing.

commissioning dates. The utility stated that Sheerness 2 and the Genesee units should be delayed as much as possible in order to minimize the lifetime costs and revenue requirements associated with them. It argued, however, that Sheerness 1 should not be deferred because virtually all costs associated with this unit have been expended and deferral of the unit would increase lifetime costs substantially. In addition, leaving the commissioning date for Sheerness 1 unchanged would allow for some savings in fuel costs in the operation of the Alberta Interconnected Electric System (AIS).

Alberta Power took the position that the first unit of the Genesee project should not precede the second unit of the Sheerness project but did not give reasons. It simply referred to the Board's own reasons for placing Sheerness ahead of Genesee given in the original decisions on these projects. It also supported the commissioning of the B.C. Tie on the currently-approved schedule because of the many benefits associated with an interconnection with B.C. Hydro and because the tie has potential as a low-cost source of energy.

2.3 TransAlta Utilities Corporation

TransAlta supported Alberta Power's position of deferring all units except Sheerness 1 because such a sequence would maximize the long-term savings to the power consumers of Alberta. TransAlta took the position that energy would be imported across the B.C. Tieline and in its analyses of lifetime costs and revenue requirements it assumed a 16-mills/kW.h price for this energy.

TransAlta also supported Alberta Power's position respecting the commissioning of the B.C. Tie and the ordering in sequence of the Sheerness and Genesee units.

2.4 Edmonton Power

Edmonton Power supported the currently-approved schedule of commissioning dates for the Sheerness and Genesee units on the grounds that this sequence provided

economic stability and employment in the 1985-1986 period without increasing lifetime costs or revenue requirements. Thus it argued that the sequence satisfied the two primary criteria set out by that utility – economic stability and efficiency.

While the utility supported the existing schedule, it stated that, if the ERCB deemed some deferral necessary, it would support an alternate sequence (Sequence 9 in Table 2). This sequence would effectively put the first Genesee unit ahead of the second Sheerness unit. Edmonton Power argued that this sequence would also provide economic stability in the 1985-1986 period and would reduce both lifetime costs and revenue requirements. It also stated that it would support a variation of its alternate sequence that would not defer the commissioning of the B.C. Tie (Sequence 9a in Table 2).

2.5 The Cities of Calgary and Lethbridge

Calgary supported the maximum-deferral sequence. It argued that the primary consideration should be the need for the plants and that emphasis should be placed on the short-term savings to the consumer rather than the long-term costs. It stated that social goals and objectives should not be met through utility rates. Furthermore, the ERCB should give some consideration to the removal of what Calgary termed excess plant.

Calgary supported Alberta Power's position on the commissioning of the B.C. Tie and the ordering of the Sheerness and Genesee units. It saw no evidence to indicate that the order of the units should be altered.

Lethbridge supported the maximum deferral of the Sheerness Unit 2 and the Genesee units. It indicated that consumers are currently not in a position to easily absorb electricity rate increases, and that such increases should be delayed, if possible, to a time when the economy has improved and they can be more easily absorbed. It also stated that it opposed funding make-work projects through the electric utilities.

2.6 The Industrial Power Consumers Association of Alberta

IPCAA supported the position that the Sheerness and Genesee units should be deferred to the latest possible dates as identified by the EUPC (Sequence 3 in Table 2). It indicated that its primary concern was the short-term minimization of electricity costs to consumers in Alberta. An increase in costs to IPCAA's members could adversely affect their competitive position in the market place.

IPCAA also supported commissioning the B.C. Tie on its currently-approved schedule.

2.7 Coal Companies

Manalta indicated its support for keeping the current commissioning date for Sheerness 1. The firm has carried out a considerable portion of the work required to expand the Montgomery mine in order to supply coal to the unit. Expenditures have been delayed as long as possible but the firm finds it has no more flexibility relating to scheduling. A further delay of Sheerness 1 would impose hardship and inconvenience on Manalta, its employees, and its suppliers.

Luscar indicated its support of the deferral of Sheerness 2 to a date when it is required by the AIS on the understanding that the unit would precede Genesee 2. It stated that additional uncertainty should not be placed on the construction of Sheerness 2. The firm has undertaken considerable preliminary work in order to provide coal to Sheerness 2 but indicated that a further delay could be accommodated.

Fording indicated its support for the currently-approved schedule. However, if the ERCB deemed that some delay were necessary, the firm stated that it would support Edmonton Power's alternative sequence. Fording indicated that the monies expended by towns and construction firms would amount to lost capital if a further delay were ordered. The firm is of the opinion that such losses should be minimized. Fording also stated that electricity export possibilities should be vigorously pursued.

2.8 The Engineering and Construction Trades

INTEG, Stuart Olson Construction, Cana Construction, the Electrical Contractors Association, the Energy and Chemical Workers Union, and the Alberta & N.W.T. Building and Construction Trades Council all supported the currently-approved schedule for the construction of the Genesee Units 2 and 1. They stated that the project should go ahead as soon as possible in order to provide employment in the construction trades. These interveners contended that construction and labour costs are lower now than they will be in a few years, so a cost saving can be realized through early completion of the units. They expressed concerns that a further delay at this time could lead to a loss of expertise and skilled manpower due to people leaving the province or dropping out of the work force. The cost of repatriating these resources could be quite high, especially if job prospects were to improve elsewhere in the provincial economy at that time.

Identical concerns were expressed by both Southern Alberta and Alberta & N.W.T. Building and Construc-

tion Trades Councils in their positions in favour of the commissioning of Sheerness Unit 2 according to its presently-approved schedule. These councils were supported by Cana Construction.

The Alberta & N.W.T. Building and Construction Trades Council and its Southern Alberta counterpart stated that the B.C. Tie should be delayed. They indicated that one reason the construction of the plants can be delayed is because energy will be imported over the tie. If the tie were delayed, the energy would not be imported and the power plants could be built, thus preserving jobs in the province.

2.9 Counties, Towns, and Villages

The Villages of Warburg, Thorsby, and Breton and the County of Leduc No. 25 were in favour of commissioning the Genesee units according to the presently-approved schedule. They noted that the current residents are bearing the cost of the development of lots and recreational facilities and the expansion of local utility services, which were put in place in anticipation of the early completion of the units. These facilities are underutilized and associated revenues will not be realized until the start-up of the units. The county indicated that further delay might create additional expenses associated with road maintenance. Each intervener indicated that the business spin-offs and job opportunities for residents resulting from the construction of the units would be beneficial at this time.

The Town of Calmar supported this position as well, stating that underutilized infrastructure was also a problem for the town. While these developments were not undertaken specifically in anticipation of the Genesee project, commissioning of the units would help alleviate the problem.

Similar reasons were cited by the Town of Hanna and District in support of commissioning Sheerness Unit 1 in January of 1986. The town identified further benefits that would be realized from a secure water supply and irrigation spin-offs associated with the start-up of Sheerness 1. The town referred to an agreement with Alberta Environment for additional water supply and said that the agreed-to schedule would not be met if the Sheerness Unit 1 were delayed. A delay in the commissioning of the unit may delay these benefits and increase the cost of water to the town. The town was in favour of delaying the commissioning of Sheerness 2 and the Genesee units in order to reduce the cost of electricity to Alberta consumers.

2.10 Planning Commissions and Economic Development Authorities

The Palliser Regional Planning Commission supported the view that the first unit of the Genesee project should not precede the second unit of the Sheerness project. It also supported the position taken by the Town of Hanna and District.

3 DEFINITION OF THE ISSUES

After consideration of all evidence before it, the Board believes the relevant issues to be:

- the commissioning date for the B.C. Tieline,
- the generating capacity requirements and timing to provide adequate capacity and sufficient energy for loads on the Alberta interconnected system during the 1986-1991 period,
- the commissioning date for Sheerness Unit 1,
- the commissioning dates for Sheerness Unit 2 and Genesee Unit 2, and
- the commissioning date for Genesee Unit 1.

4 VIEWS OF THE BOARD

BASIS FOR CONSIDERATION

Having carefully considered all of the evidence, the Board believes that some unique circumstances apply to the determination of the commissioning dates for the Sheerness and Genesee units and that the decision should not be based on a single criterion but a combination of factors. Principal criteria are:

- the need for the Sheerness and Genesee units to reliably supply the projected electric load, and
- the lifetime costs of the expansion sequence.

Consideration should also be given to:

- the impact on electric consumers,
- the impact on communities, and
- the impact on the economy.

Furthermore, the Board believes that concerns regarding the B.C. Tie should be resolved prior to determining the need for generating units to reliably meet the load in the 1986-1991 period.

The Board accepts the 1984 EUPC forecast of energy and peak demand and the EUPC's capacity- and energy-planning criteria as a basis for determining the need for generating capacity to reliably meet the projected demand for the 1986-1991 period. However, it

also believes that in light of recent events, such as the stimulus of the economy due to the Western Accord and expansion of oil sands developments, the current EUPC forecast of demand may prove to be on the low side. Therefore, it believes that the final determination of the need for generating units in the 1986-1991 period should give some recognition to the possibility of a higher forecast.

The Board believes that the lifetime cost of the final expansion sequence chosen should be minimized to the extent possible. It also believes that the impact on the consumers of electricity is an important consideration, and that the evaluation of revenue requirements associated with the chosen expansion sequence is an appropriate assessment of this impact. In this regard, minimization of the short-term cost to the consumers should be given more weight than the longer-term impact. The Board subscribes to the submissions at the hearing that power costs to the consumer should be minimized in the short run to allow full economic recovery and believes that longer term increases will be buffered by an increase in the number of customers as the economy recovers from the recent recession.

4.1 The B.C. Tie: Commissioning Date and Tieline Energy

Approval of the B.C. Tieline was issued by the Board in 1980. Construction is in the final stages, with completion scheduled for late 1985. TransAlta's evidence indicated that virtually all of the construction costs are fully committed and any deferral of the commissioning date would not reduce or delay expenditures. While the commissioning date for the B.C. Tieline was not in question when the Board convened the hearing, it became an issue because of its potential impact on the need for capacity to meet the projected load. Consequently, some of the generation sequences presented in the Technical Information Package assumed a commissioning date other than January 1986.

The Board accepts that, if consideration were given only to meeting the load forecast, the B.C. Tieline could be deferred beyond its currently-approved commissioning date. However, deferral would not reduce lifetime costs and thereby provide any cost benefit to the consumer. In fact, deferral would actually lead to increased costs. For example, deferral would preclude the purchase of economy energy that could reduce the total cost of energy to consumers by displacing more expensive energy in the Alberta system. The B.C. Tieline will provide additional advantages, such as greater reliability in supplying the loads in southern Alberta, which would have greater importance with any deferral of units at the Sheerness site.

In the Board's view the advantages of commissioning the B.C. Tieline in accordance with the current schedule far outweigh any disadvantages. Accordingly, the Board concludes that the B.C. Tieline should be commissioned as scheduled in January 1986.

There were signficant differences in the views of several participants respecting the degree to which the B.C. Tieline would be utilized and the price of any energy imported over it. TransAlta contended that B.C. Hydro will have significant excess generating capacity for several years which will be available at favourable prices. It provided evidence of 1984 purchases at 12 and 18 mills/kW.h and, in estimating the lifetime costs and revenue requirements for the various generating sequences, it assumed a purchase price of 16 mills/kW.h. Edmonton Power contended that there was no assurance that there would be excess capacity in British Columbia but, in any event, other prospective purchasers would also be interested in purchasing that energy and consequently, the price could be expected to be higher. It used a cost equivalent to gas-fired energy in estimating costs and revenues for the generation sequences.

Although there was only limited evidence as to the availability of energy from B.C. Hydro, the Board agrees that the current excess capacity situation is likely to continue into the 1990s and that purchases are likely to be at favourable prices. Accordingly, it assumed that the purchase price of energy would be 16 mills/kW.h for 1984. Prices in other years were assumed to escalate at the rate of inflation. It also adopted yearly energy imports consistent with those assumed by the utilities in the Technical Information Package.

4.2 Generating Capacity Requirements for the 1986-1991 Period

Figure 1 shows the relationship between the peak load estimated in the 1984 EUPC forecast and the load carrying capability (LCC) of the interconnected system for four generation expansion sequences.

(1) Presently-approved sequence:
The presently approved commissioning dates for the four Sheerness and Genesee units;

(2) Maximum-deferral sequence:
Commissioning dates that would be consistent with the maximum deferral of the four generating units;

(3) Sequence A:
Same as maximum-deferral sequence but with the first unit advanced from 1989 to 1988;

(4) Sequence B:
Same as Sequence A but with the second unit advanced from 1990 to 1989.

The presently-approved sequence would result in substantial surplus load carrying capability (SLCC) until 1992. The maximum-deferral sequence would essentially eliminate the SLCC in 1988 and in 1989. Sequence A would increase the SLCC in 1988 but only marginally in 1989. Sequence B would increase the SLCC in both 1988 and 1989.

The Board believes that the presently-approved sequence would result in too much surplus capacity. It has considered which of the three alternatives (maximum deferral, Sequence A, or Sequence B) best meets the needs of Alberta consumers, having regard only for reliability considerations expressed as LCC. Costs and other factors related to each of these alternatives are considered in later sections that address the timing of specific generating units.

As illustrated in Figure 1, the maximum-deferral alternative would minimize SLCC and result in system LCCs that are virtually the same as the estimated peak loads in 1988 and 1989, but in 1990 and subsequent years the LCC would be significantly greater than the estimated peak load. The Board is concerned that as a result of recent developments, such as the new energy agreement between the federal and provincial governments and the rapidly expanding oil sands developments, the 1984 forecast may prove to be on the low side. In addition, should developments demonstrate that the 1984 load forecast was indeed too low there might not be sufficient time to advance the commissioning date of the next units, or to do so would result in signficant cost increases. Having regard for these factors, the Board believes it prudent to ensure more load carrying capability in 1988 and 1989 which, as shown in Figure 1, would be compatible with the maximum-deferral sequence for 1990 and subsequent years. Therefore, the Board believes the adoption of the maximum-deferral sequence for 1988 and 1989 would not be in the public interest.

Keeping these concerns in mind, the Board believes Sequence A would provide a reasonable margin between LCC and peak load in 1988 but would not do so in 1989. Sequence B, however, would provide a reasonable balance in both years and is the alternative that would best meet the expected loads in 1988 and beyond.

4.3 The Commissioning Date of Sheerness Unit 1

As explained in the foregoing assessment of generation requirements, the Board concludes that the next unit should be commissioned no later than 1988.

Evidence at the hearing indicated that construction of Sheerness 1 is virtually complete and almost all costs have already been incurred. Deferring its currently-approved commissioning date of January 1986 would increase the lifetime cost of the unit paid by Alberta consumers. The additional cost would be due to mothballing the plant and the higher system generation costs that would occur during that period because older and less efficient units would have to operate. The evidence shows that the additional lifetime cost of deferring Sheerness 1 from January 1986 to January 1989 would be $49 million (present worth) and the Board believes that commissioning the unit in 1988 would have a similar additional lifetime cost. In view of the higher costs, the Board can see no advantage in deferring the commissioning date until 1988 and concludes that it would be prudent to avoid the cost and commission the unit as presently scheduled, in January 1986.

This decision provides the additional advantage of relieving concerns expressed by the Town of Hanna regarding its water supply.

4.4 The Commissioning Date for Sheerness 2 and Genesee 2

Based on its assessment of need as described under section 4.2, the Board is of the view that one unit should be commissioned in 1989 and another in 1990. These units should be Sheerness 2 and Genesee 2.

Using the evidence presented, the Board analysed the impact on lifetime costs and the corresponding impact on the consumer resulting from commissioning Sheerness 2 ahead of Genesee 2 and vice versa. The Board's analysis, as well as the evidence by Edmonton Power at the hearing, show that commissioning Genesee 2 in advance of Sheerness 2 results in total lifetime costs that would be some $4 million (present worth) lower in spite of the fact that the capital cost of Genesee 2 is significantly greater than that of Sheerness 2. This somewhat surprising result is due to the fact that substantial expenditures have been made on the Genesee unit in order to meet the previously-approved commissioning date of June 1988, while relatively fewer expenditures have been made on Sheerness 2.

The Board also examined the impact of the two sequences on short-run costs to the consumer and found no impact prior to 1989. If the Sheerness unit is commissioned first, its cost will enter the rate base in 1989, and the dollars already expended on Genesee 2 will accumulate interest charges for one more full year prior to its entering the rate base in 1990. If Genesee 2 is commissioned first, capital charges would accrue for an additional year on the monies expended on Sheerness 2. Given that the cost of the Genesee unit is substantially larger than the cost of Sheerness 2, one year's accumulation of interest would be larger for Genesee 2. Consequently, the cost to the consumer in the 1989-1990 period

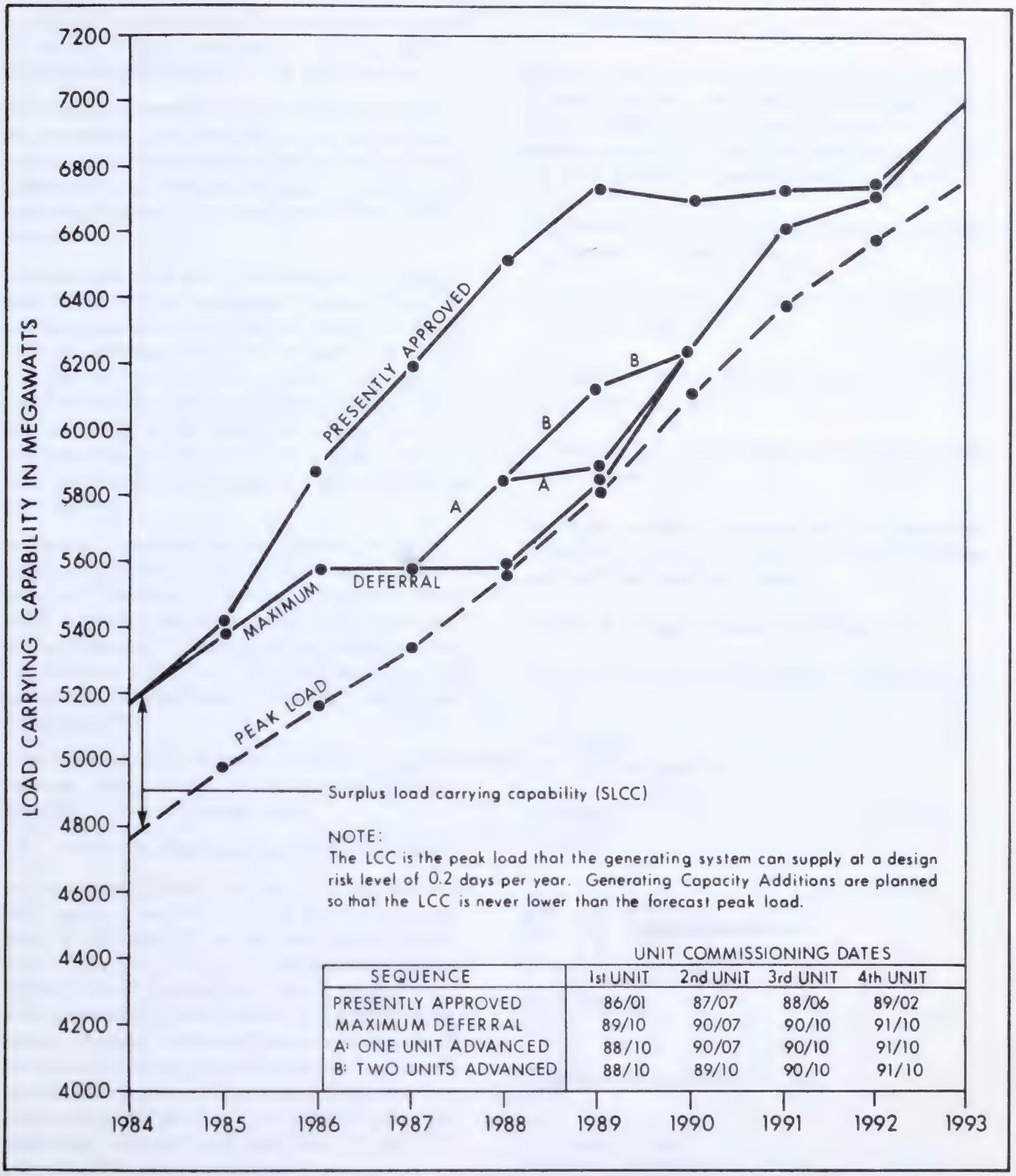

FIGURE 1 THE PROJECTED LOAD CARRYING CAPABILITY (LCC) OF THE ALBERTA INTERCONNECTED ELECTRIC SYSTEM (AIS) FOR VARIOUS UNIT COMMISSIONING DATES RELATIVE TO MAXIMUM DEFERRAL.

in terms of additions to the rate base would be lower if Genesee 2 were commissioned first and did not accumulate interest charges for an additional year.

The Board also considered the concerns expressed by the communities surrounding the Genesee project. These concerns would not be addressed by the commissioning of Sheerness 2 in 1989 and Genesee 2 in 1990. Commissioning Genesee 2 first would partially alleviate these concerns.

The final factor in the Board's analysis concerns employment. While the funds remaining to be spent on the two units may be similar, the timing and manpower profile associated with the units are quite different. The Board is of the view that Genesee 2 would have a greater positive impact on employment in the pre-commissioning phase than would Sheerness 2. Therefore, the commissioning of Genesee 2 first would partially alleviate some of the employment concerns expressed at the hearing.

In summary, the Board's primary concerns, after need, are the minimization of lifetime costs and short-term costs to the consumer. Its analysis indicates that these objectives are best served by commissioning Genesee 2 prior to Sheerness 2. Employment and community concerns reinforce this decision. Therefore, the Board is of the view that Genesee 2 should be the unit commissioned in October 1989.

With adequate load carrying capability for 1989, Sheerness Unit 2 should be commissioned when it is required, which is in October 1990.

4.5 The Commissioning Date for Genesee Unit 1

As illustrated in Figure 1, this unit is not required until 1991, and the Board notes that the load carrying capability in 1990 and 1991 is signficantly higher than the forecast peak load, thereby providing a buffer against a higher forecast. Most of the evidence presented at the hearing indicated that the deferral of units until they are required generally reduces the lifetime costs associated with the entire project, and will minimize increases in revenue requirements to the consumer in the short run. Consequently, the Board is of the view that the commissioning of Genesee Unit 1 should be in October 1991, when it will be required on the AIS.

5 DECISION

Having regard for its responsibilities under the Act and its views expressed herein, the Board is prepared, with the authorization of the Lieutenant Governor in Council, to issue approvals to confirm and amend the commissioning dates for the four generating units as follows:

(a) Sheerness Unit 1 to be commissioned as presently approved in January 1986,

(b) Sheerness Unit 2 to be deferred from July 1987 to October 1990,

(c) Genesee Unit 2 to be deferred from June 1988 to October 1989, and

(d) Genesee Unit 1 to be deferred from February 1989 to October 1991.

The orders would be of the form set out in Appendices A and B of this report, and would be subject to the terms and conditions contained therein.

DATED at Calgary, Alberta, on 15 May 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

C. J. Goodman, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

APPENDIX A
FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

HYDRO AND ELECTRIC ENERGY ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a power plant of Alberta Power Limited and TransAlta Utilities Corporation in the Sheerness area

APPROVAL NO. HE

WHEREAS Alberta Power Limited and TransAlta Utilities Corporation are the holders of Approval No. HE 8312 authorizing the construction and operation of the Sheerness power plant; and

WHEREAS the Energy Resources Conservation Board convened a public hearing to consider the most appropriate commissioning dates for Sheerness generating units 1 and 2; and

WHEREAS the Board has determined that it is appropriate to commission Sheerness Unit 1 as scheduled and defer the commissioning date of Sheerness Unit 2, subject to the conditions herein contained; and

WHEREAS the Minister of the Environment has given his approval, hereto attached, insofar as matters of the environment are concerned; and

WHEREAS the Board deems it desirable to revise and consolidate Approval No. HE 8312.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Hydro and Electric Energy Act, being chapter H-13 of the Revised Statutes of Alberta, 1980, and the Lieutenant Governor in Council having given his authorization by Order in Council, numbered O.C.____________/85 and dated ________________________ 1985, hereby orders as follows:

1. The construction and operation by Alberta Power Limited and TransAlta Utilities Corporation (hereinafter called "the Operator") of the Sheerness power plant and associated facilities located in the Sheerness area, is approved, subject to the terms and conditions herein contained.

2. The power plant and associated facilities shall be located as generally shown on the site plan, hereto attached as Appendix A.

3. Subject to the other provisions of this approval, the power plant shall be constructed and operated in accordance with

(a) Application No. 9759 by Alberta Power Limited to the Board dated 2 November 1976 and supplementary information and evidence given in support of the application at a hearing on 16 May 1978,

(b) Application No. 790606 by Alberta Power Limited to the Board dated 5 September 1979,

(c) Application No. 830702 by Alberta Power Limited to the Board dated 20 July 1983,

(d) Application No. 830799 by the Operator to the Board dated 22 August 1983 and supplementary information and evidence given in support of the application at a hearing on 28 September 1983, and

(e) Board Proceeding No. 840837 and information and evidence given at a hearing on 22 January 1985.

4. (1) The power plant shall consist of two units, each of 400-megawatts nominal capacity.

(2) The units shall be commissioned such that Unit 1 is available to the system on 1 January 1986 and Unit 2 is available on 1 October 1990, unless the Board otherwise stipulates.

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* This is only a form of approval. The approval, when issued, may have minor variations from that set out here.

5. (1) The cooling pond required for units 1 and 2 shall be located as generally shown in Appendix A.

(2) The cooling pond shall be operated to a full supply level of 802.7 metres above sea level.

(3) The cooling pond shall be provided with make-up pumphouse and pipeline facilities from the Red Deer River to the plant site as generally shown in Appendix B hereto attached.

(4) The blowdown control structure, pipeline and related facilities shall be located as generally shown in Appendix B.

6. Ash from the power plant shall be disposed of in worked-out sections of the coal mine located east of the power plant.

7. Notwithstanding the foregoing provisions, the permitted area of the power plant and related facilities shall include Sections 31, 32 and the West half of Section 33 in Township 28 and Sections 5 and 6 in Township 29, all in Range 13, West of the 4th Meridian, or as otherwise stipulated by the Board.

8. (1) Not later than 31 December 1985, the Operator shall provide to the Board a complete revised schedule for Sheerness 2, covering planning, design, construction and commissioning phases, and showing all key dates in the schedule.

(2) The Operator shall submit to the Board quarterly progress reports for Sheerness units 1 and 2. Any major deviation from the respective schedules for Sheerness units 1 and 2 shall be indicated.

(3) The Operator shall notify the Board in writing within one month upon the commissioning of each unit.

9. (1) Insofar as it pertains to matters of the environment, this application is subject to the approval of the Minister of the Environment.

(2) The approval of the Minister of the Environment, in accordance with subclause (1), is attached hereto as Appendix C, and this approval is subject to the terms and conditions therein contained.

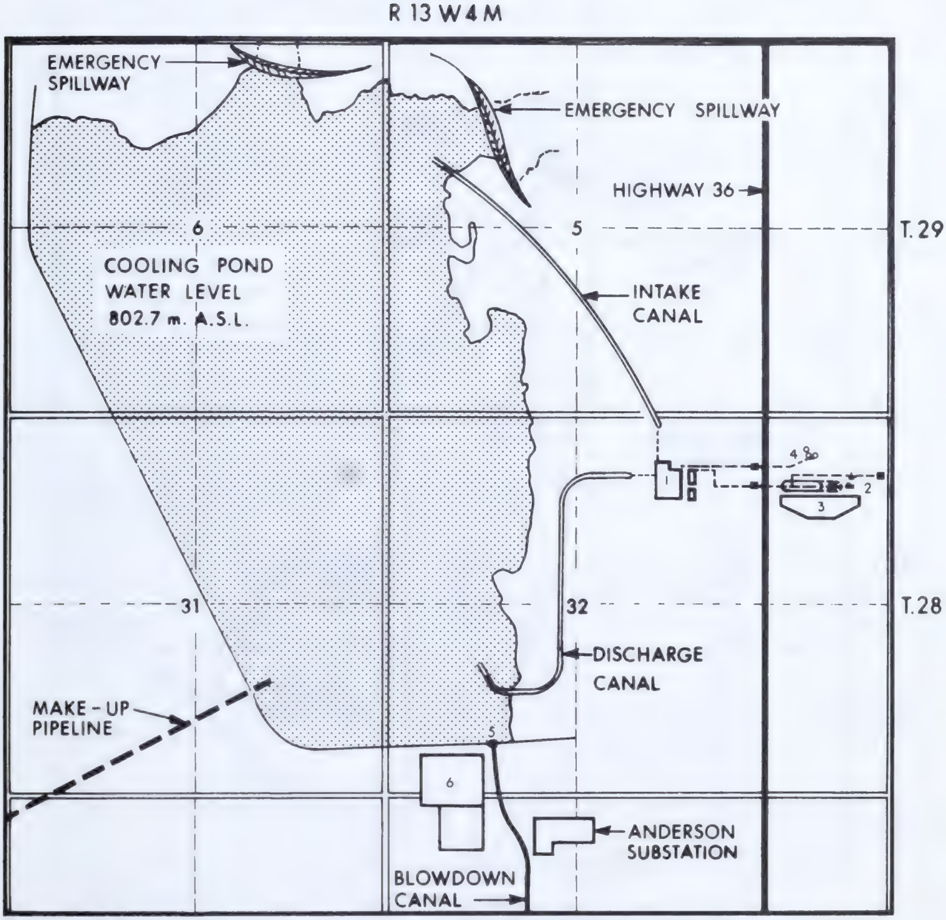
10. (1) Attached hereto as Appendix D, and made part of this approval, is the Order of the Lieutenant Governor in Council authorizing the granting of this approval.

(2) This approval is subject to the terms and conditions, if any, prescribed by the Order of the Lieutenant Governor in Council, as set out in Appendix D.

11. Approval No. HE 8312 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this day of 1985.

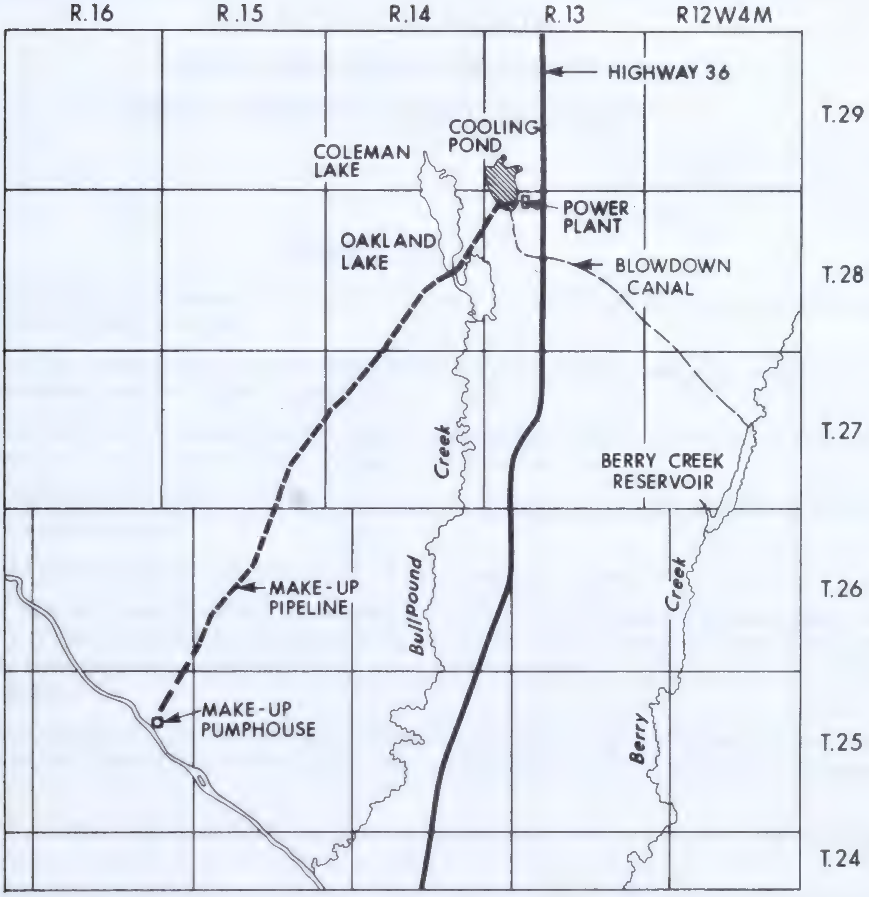
ENERGY RESOURCES CONSERVATION BOARD



APPENDIX A TO APPROVAL NO. HE
SHEERNESS POWER PLANT AND FACILITIES
PREVIOUS APPROVAL NO. HE 8312

LEGEND

1. POWER PLANT
2. COAL HANDLING PLANT
3. COAL STORAGE PILE
4. ASH HANDLING PLANT
5. BLOWDOWN CONTROL STRUCTURE
6. SEWAGE LAGOON



APPENDIX B TO APPROVAL NO. HE
COOLING POND MAKE-UP & BLOWDOWN FACILITIES
PREVIOUS APPROVAL NO. HE 8312

APPENDIX B
FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

HYDRO AND ELECTRIC ENERGY ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a power plant of The City of Edmonton in the Genesee area

APPROVAL NO. HE

WHEREAS The City of Edmonton is the holder of Approval No. HE 8320 authorizing the construction and operation of the Genesee power plant; and

WHEREAS the Energy Resources Conservation Board convened a public hearing to consider the most appropriate commissioning dates for Genesee generating units 1 and 2; and

WHEREAS the Board has determined that it would be appropriate to defer the commissioning dates for the Genesee generating units 1 and 2, subject to the conditions herein contained; and

WHEREAS the Minister of the Environment has given his approval, hereto attached, insofar as matters of the environment are concerned; and

WHEREAS the Board deems it desirable to revise and consolidate Approval No. HE 8320.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Hydro and Electric Energy Act, being chapter H-13 of the Revised Statutes of Alberta, 1980, and the Lieutenant Governor in Council having given his authorization by Order in Council, numbered O.C.____________/85 and dated__________________________ 1985, hereby orders as follows:

1. The construction and operation by The City of Edmonton (hereinafter called "the Operator") of the Genesee power plant and associated facilities located in the Genesee area, is approved, subject to the terms and conditions herein contained.

2. Subject to the other provisions of this approval, the power plant shall be constructed and operated in accordance with

(a) Application No. 780024 by the Operator to the Board dated 12 January 1978 and supplementary information and evidence given in support of the application at a hearing on 25 July 1978,

(b) Application No. 810683 by the Operator to the Board dated 20 September 1981 and supplementary information and evidence given in support of the application at a hearing on 25 November 1981,

(c) Application No. 821000 by the Operator to the Board dated 18 October 1982,

(d) Application No. 830799 by Alberta Power Limited to the Board dated 22 August 1983 and supplementary information and evidence given in support of the application at a hearing on 28 September 1983, and

(e) Board Proceeding No. 840837 and information and evidence given at a hearing on 22 January 1985.

3. (1) The power plant shall consist of two units, each of 400-megawatts nominal capacity.

(2) The units shall be commissioned such that Unit 2 is available to the system on 1 October 1989 and Unit 1 is available on 1 October 1991, unless the Board otherwise stipulates.

4. The power plant and related facilities shall be located as generally shown on the attachment to this approval, marked Appendix A.

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* This is only a form of approval. The approval, when issued, may have minor variations from that set out here.

5. The power plant shall be cooled by a cooling pond constructed in accordance with the following provisions:

(1) The cooling pond shall be located as generally shown in Appendix A, or as otherwise stipulated by the Board.

(2) The cooling pond shall be designed for and operated at a maximum full supply level of 731.5 metres above sea level.

(3) The Operator shall maintain a buffer zone around the cooling pond.

(4) The buffer zone required by subclause (3) shall extend not less than 10 metres measured horizontally from the cooling pond shoreline at the full supply level.

(5) The cooling pond shall be provided with independent make-up and blowdown pipeline facilities from the North Saskatchewan River to the plant site. The pipelines shall be located generally as shown on Appendix A on a right of way not to exceed 30 metres in width, or as otherwise stipulated by the Board.

6. (1) Ash from the power plant shall be disposed of in worked-out sections of the coal mine.

(2) Until such time as the mine can accept ash from the power plant, a temporary ash disposal area may be used.

(3) The temporary ash disposal area required for disposal of ash shall be located as generally shown in Appendix A, or as otherwise stipulated by the Board.

(4) The Operator shall, in consultation with the Department of the Environment, investigate means of salvaging topsoil for use in reclamation of the temporary ash disposal area.

7. Notwithstanding the foregoing provisions, the permitted area of the power plant and related facilities shall include Sections 22 to 27 inclusive and the South halves of Sections 34 and 35, all in Township 50, Range 3, West of the 5th Meridian, or as otherwise stipulated by the Board.

8. (1) Not later than 31 December 1985, the Operator shall provide to the Board a complete revised project schedule for the plant covering planning, design, construction and commissioning phases, and showing all key dates in the schedule.

(2) The Operator shall submit to the Board quarterly progress reports indicating any major deviation from the schedule which may cause a delay in the in-service dates of the generating units.

(3) The Operator shall notify the Board in writing within one month upon the commissioning of each unit.

9. (1) Insofar as it pertains to matters of the environment, this application is subject to the approval of the Minister of the Environment.

(2) The approval of the Minister of the Environment, in accordance with subclause (1), is attached hereto as Appendix B, and this approval is subject to the terms and conditions therein contained.

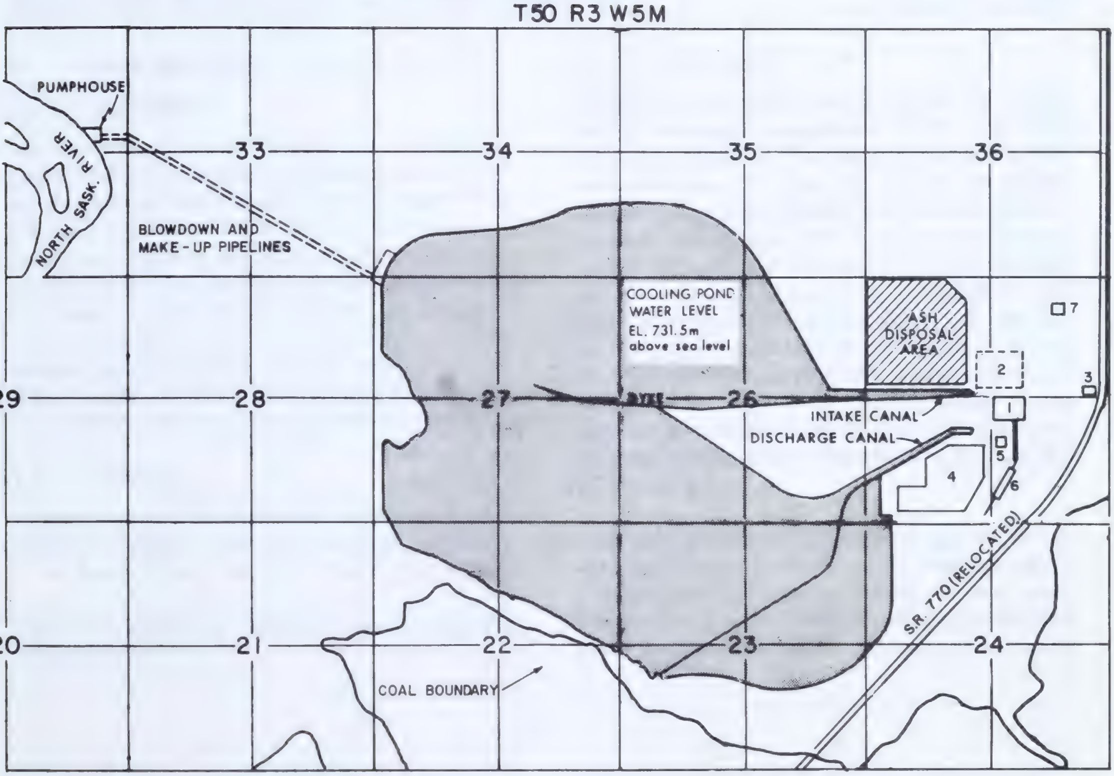
10. (1) Attached hereto as Appendix C, and made part of this approval, is the Order of the Lieutenant Governor in Council authorizing the granting of this approval.

(2) This approval is subject to the terms and conditions, if any, prescribed by the Order of the Lieutenant Governor in Council, as set out in Appendix C.

11. Approval No. HE 8320 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this day of 1985.

ENERGY RESOURCES CONSERVATION BOARD



APPENDIX A TO APPROVAL NO. HE

GENESEE POWER PLANT AND FACILITIES

PREVIOUS APPROVAL NO. HE 8320

LEGEND

1. POWER PLANT
2. SWITCHYARD (PROPOSED)
3. STATION PARKING
4. WASTE POND
5. ASH HANDLING
6. COAL HANDLING PLANT
7. WATER RESERVOIR

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

MUNICIPAL DISTRICT OF FOOTHILLS NO. 31 PURSUANT TO SECTION 34 OF THE PIPELINE ACT

Decision D 85-22
Application 850316

1 INTRODUCTION

1.1 Application

The Municipal District of Foothills No. 31 (MD) requested that the Board direct, pursuant to section 34 of the Pipeline Act, that Canadian Western Natural Gas Company Limited (CWNG) lower its 273-millimetre (mm) outside diameter pipeline crossing Secondary Road 549 through the northwest quarter of section 4, township 21, range 2, west of the 5th meridian, and remove a valve assembly and vault on the 355-mm outside diameter pipeline crossing the same road between the NW 1/4 Sec 35-20-2 W5M and the SW 1/4 Sec 2-21-2 W5M, all at no cost to the municipality.

1.2 Hearing

A public hearing of the application was held on 23 April 1985 in Calgary with C. J. Goodman, P.Eng., N. A. Strom, P.Eng., and E. G. Fox, P.Eng., sitting.

Those who appeared at the hearing are shown in the following table.

1.3 Background

CWNG's 273-mm outside diameter pipeline was installed in 1925, apparently in accordance with the code of that day. It was not known if the present road existed in 1925 but in any case a 20-metre (m) right of way (ROW) would have been normal for that time. At a different location on Secondary Road 549 a valve and vault assembly (vault) was installed in 1928 on CWNG's 355-mm outside diameter pipeline outside any original 20-m road ROW. In 1954, CWNG replaced the original vault and the installation was still outside the existing 20-m road ROW. A road widening to 30 m took place in 1968 and resulted in the vault being partially located on the expanded road ROW. There is some uncertainty as to the exact location of the vault related to the expanded ROW boundary.

In late August 1984, the MD decided to upgrade Secondary Road 549 to a 40-m ROW to meet current secondary road standards. Due to this upgrading, the vault is now located well within the road ROW, and the proposed road profile would result in the 273-mm pipeline being

THOSE WHO APPEARED AT HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Municipal District of Foothills No. 31 (MD) J. Pashniak	F. Ball T. Motil S. Bulych, P.Eng.
Canadian Western Natural Gas Company Limited (CWNG) C. K. Sheard	E. W. Phipps, P.Eng. J. H. Parkinson, P.Eng.
Energy Resources Conservation Board staff A. Gervais A. Cassley, P.Eng. P. V. Derbyshire	

partially exposed in the ditch. Although the parties agreed that the 273-mm outside diameter pipeline needed to be lowered and the vault removed, no agreement on the matter of costs could be negotiated.

This impasse on cost sharing could not be resolved by the two parties and resulted in the MD submitting an application to the Board requesting a Board direction under section 34 of the Pipeline Act.

At the hearing the Board noted that both parties agreed on the work to be done and that the construction was scheduled to begin within a few days of the hearing. Therefore, pursuant to section 34 of the Pipeline Act, it directed CWNG to lower its 273-mm outside diameter pipeline crossing Secondary Road 549 through the NW 1/4 Sec 4-21-2 W5M, to an adequate depth and over an adequate linear extent, and to remove the vault from the 355-mm outside diameter pipeline crossing the same road between the NW 1/4 Sec 35-20-2 W5M and the SW 1/4 Sec 2-21-2 W5M. The Board reserved its decision regarding the allocation of costs.

2 ISSUES

The Board considers the only remaining issue to be that of allocation of costs.

3 VIEWS OF THE PARTICIPANTS

3.1 MD of Foothills

The MD indicated that its policy is to try to alter road design profiles to accommodate pipelines in a safe manner. However, at the NW 1/4 Sec 4-21-2 W5M road crossing this was not possible and lowering of the line is necessary.

Furthermore, even if the road was not upgraded, the MD was concerned that, because the existing pipe cover is very shallow, it poses a hazard to any excavators working along the ditch or it could be subjected to impact damage from an out-of-control vehicle. It was the MD's position that, because the pipeline does not meet the currently-regulated depth-of-cover requirements, and because of the described hazards, it should be lowered independently of any road works, and therefore the MD should not be required to bear any of the costs associated with the lowering.

The MD pointed out that its current regulations provide for costs of moving pipelines affected by roadworks to be borne by the pipeline company. However, no such agreement was in place for this specific crossing. The MD stated that, in discussions with CWNG, agreement had been reached that the necessary lowering should be done. The point of contention and disagreement was the allocation of the cost of the lowering.

In regard to the vault removal, the MD again expressed concern that as the vault is now within the road ROW it poses a hazard to the public and it could be subject to damage by vehicles. However, it was suggested by the municipality that if it were required to share any cost of the vault removal, other alternatives would be investigated, such as guarding the vault in some manner.

3.2 CWNG

CWNG stated that its 273-mm outside diameter pipeline was installed in 1925 in accordance with the code of that day and is considered to be in a safe operating condition at a low stress and with no record of any corrosion. CWNG argued that it would be impossible for the company to comply with retroactively-applied current regulations at all its road crossings.

CWNG stated that lowering was necessary only to accommodate the levels of the proposed road ditch. It pointed out that it was CWNG's policy to require municipal districts to pay for pipeline alterations made necessary by road improvements. However, in this case, because the pipeline will be lowered to conform to current standards, CWNG indicated that it was willing to pay half the costs of lowering the line, even though it believed there is no legal obligation for it to do so. It stated that, in this case, it had agreed with the MD that the work should be done and that it was prepared to undertake the work.

Regarding the vault removal, CWNG pointed out that the vault had originally been placed outside the road ROW and successive road widenings had now put the vault within the road ROW. As it had no way of predicting such encroachment during initial location of its facilities, CWNG argued that, although it was prepared to remove the vault, the costs of the removal should be borne completely by the MD. CWNG confirmed that the vault would not be replaced as it has sufficient installations on the rest of the line to satisfy its operational requirements.

4 VIEWS OF THE BOARD

The Board notes that CWNG owned the pipeline ROW up to the original road ROW and no specific agreements were in place that would specify who should pay for either the pipeline lowering or vault removal. CWNG might have been expected to anticipate an upgrading of the original road ROW, although this is questionable for a line installed some 60 years ago. However, an expansion beyond the original road ROW infringing on the pipeline ROW would be almost unpredictable.

The Board agrees that CWNG should bear the cost of lowering the pipeline across the original 20-m road ROW but that the MD should assume the costs of alterations

imposed on the pipeline outside that original road ROW. The Board accepts that the cost of lowering below the original road ROW is about equal to the cost involved in the work beyond the original 20-m road ROW. Accordingly, each party should bear half the cost.

In the case of the vault, the Board notes that it was originally located completely off the road ROW but on the pipeline ROW, and the road expansions infringed on the vault, resulting in the accepted need to have the vault removed. The Board therefore agrees that the costs associated with the vault removal should be borne by the MD of Foothills.

5 DECISION

For the reasons outlined, the Board directs that

(1) The costs of lowering the 273-mm pipeline shall be shared equally by Canadian Western Natural Gas Company Limited and the Municipal District of Foothills No. 31, and

(2) The costs of removing the valve and vault assembly shall be borne entirely by the Municipal District of Foothills No. 31.

DATED at Calgary, Alberta, on 27 May 1985.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman

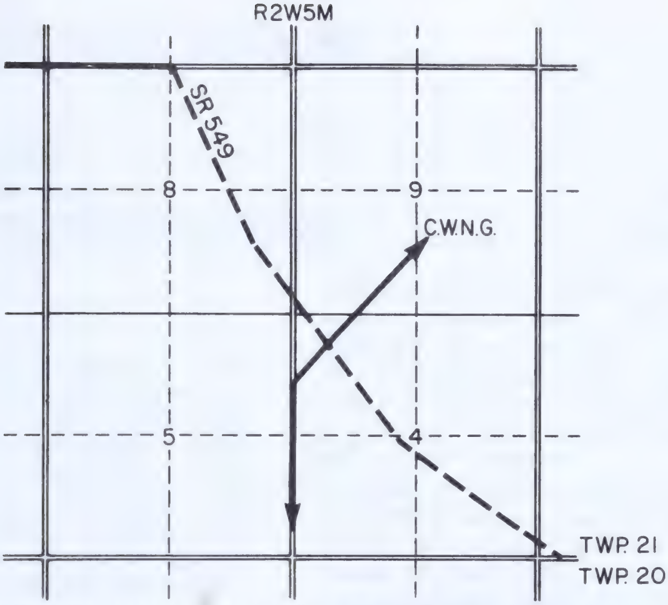
C. J. Goodman, P.Eng.
Board Member

N. A. Strom

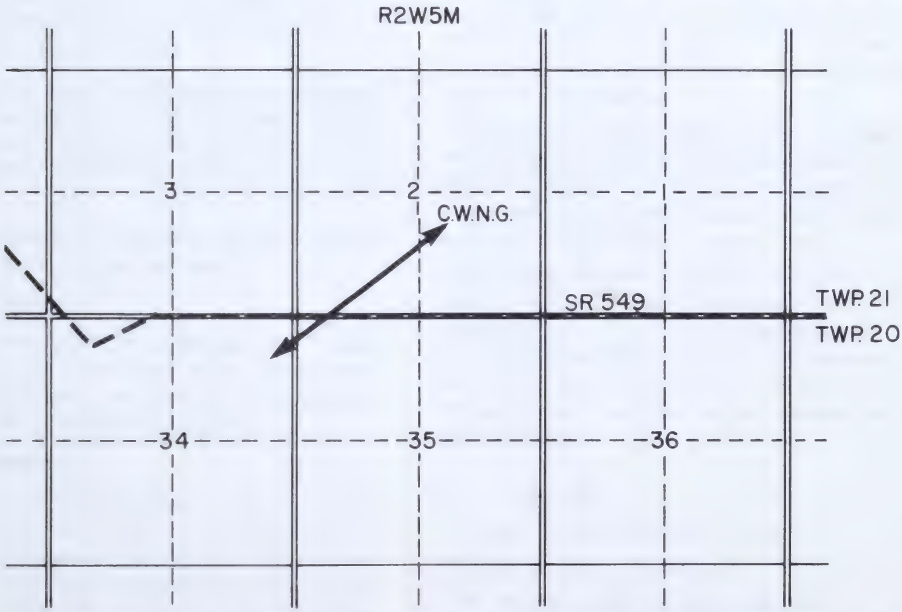
N. A. Strom, P.Eng.
Board Member

E. G. Fox

E. G. Fox, P.Eng.
Acting Board Member



273.1 mm TURNER VALLEY LINE LOWERING AT HWY. NO. 549
N.W. 1/4 SEC 4 TWP. 21 RGE. 2 W5M



355.6 TURNER VALLEY LINE VALVE REMOVAL AT HWY. NO. 549
N.W. 1/4 SEC. 35 TWP. 20 RGE. 2 W5M

MUNICIPAL DISTRICT OF FOOTHILLS NO. 31
APPLICATION NO. 850316

D85-22
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

RANGER OIL LIMITED RATEABLE TAKE OF GAS MAPLE GLEN UPPER MANNVILLE B POOL

Decision D 85-23
Application 850010

1 INTRODUCTION

1.1 The Application

Ranger Oil Limited applied under section 23 of the Oil and Gas Conservation Act (the Act) for an order to set the total withdrawal rate of gas from the Maple Glen Upper Mannville B Pool (the B Pool) and to distribute gas production in an equitable manner among the wells in the B Pool. Ranger also applied under section 45 of the Act to have the rateable take order made retroactive to the date of application; however, the applicant withdrew the request for retroactivity at the hearing.

1.2 The Hearing

The application was considered by the Board at a public hearing on 24 and 25 April 1985, in Calgary, Alberta, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and H. Antonio, P.Eng., sitting.

The hearing was originally scheduled as an examiner hearing but was rescheduled following application by Poco Petroleums Ltd. to have the Board conduct the hearing because of the important policy considerations involved.

Those who appeared at the hearing and abbreviations used in this report are listed in Table 1.

1.3 Interventions

Interventions were filed by Poco, Wainoco, and Farries Engineering (1977) Ltd. on behalf of the Altex Group. CWNG and TCPL intervened for the purposes of cross-examination and presentation of argument.

1.4 Background

The B Pool is a non-associated, sweet gas pool underlying a large area of the Maple Glen Field as illustrated in Figure 1. The pool was discovered in 1974 when a well was drilled in legal subdivision (Lsd) 10-26-36-16 W4M (10-26 well). The 10-26 well began producing from the B Pool in March 1976 at an average rate of 73 thousand cubic metres per day (10^3 m^3/d) of gas and had produced about 97 million cubic metres (10^6 m^3) of gas to December 1984.

The B Pool contains 36 wells, 20 of which are currently producing gas. Ranger is the licensee of two of the currently producing wells, while the Altex Group and Poco are licensees of 12 and 6 of the producing wells, respectively. Wainoco operates 15 of the producing wells in the pool. The total production from the B Pool to December 1984 was 420 x 10^6 m^3. During 1984, about 10 per cent was produced from the Ranger wells, while 65 and 25 per cent was produced from the Altex Group and Poco wells, respectively.

Ranger has lands including sections 2, 10, 11, 12, and 14-36-16 W4M under a gas sales contract to Pan-Alberta Gas Ltd. (Pan-Alberta) specifying a Daily Contract Quantity (DCQ) of 50 x 10^3 m^3/d. The contract is currently being fulfilled by production from a well in Lsd 13-10-36-16 W4M (the 13-10 well). It also holds a contract with Pan-Alberta specifying a DCQ of 113 x 10^3 m^3/d for gas produced from an area outside of the B Pool boundary as well as from sections 3 and 4-36-16 W4M within the B Pool. A well in Lsd 8-3-36-16 W4M (the 8-3 well) is currently producing to the latter contract.

The remainder of the B Pool is subject to several contracts, including a reserves-based area contract to TCPL with the flexibility to produce the gas required from any of the lands in the B Pool dedicated to the contract, as well as numerous industrial market contracts.

A well was drilled in Lsd 16-12-36-16 W4M (the 16-12 well) in August 1984 and completed in the B Pool in September 1984. A deliverability test performed at the well in November 1984 indicated an absolute open flow potential of 170 x 10^3 m^3/d for the B Pool. The well was subsequently shut in and has not been placed on production to date.

2 ISSUES

The Board considers the issues to be

- the delineation of the B Pool,
- the need for a rateable take order, and
- if an order is needed, the type and details of the order to be issued.

3 POOL DELINEATION

3.1 Ranger's Views

Ranger stated that its interpretation of the B Pool was based on log correlation. Net pay values of the wells

were based on cutoffs of 50 per cent on the Spontaneous Potential and Gamma Ray logs and 10 per cent density-porosity cutoff.

The applicant contended that its map accurately reflects net pays but not necessarily well capability, and that there are wells in the pool that do not have proven reserves associated with them. Ranger indicated that drill-stem test (DST) data had not been considered in its map interpretation and contended that poor test results were not sufficient reason to omit wells from the pool. It submitted that its map was of net pay and not reserves.

In its application, Ranger stated that it had derived its density-porosity cutoff from the well in Lsd 6-35-35-16 W4M (the 6-35 well). The Hackett sand in the well had porosities not exceeding 10.5 per cent and tested gas on a DST at a rate of 8.5 x 10^3 m^3/d. The well had not been included as a capable gas well since Ranger considered it to be a potential oil well. In addition, it acknowledged that although the sand reservoir in the well in Lsd 2-11-37-16 W4M (the 2-11 well) is structurally high, and as a result has less stratigraphic section, it is equivalent to the Hackett sand in the B Pool. Ranger noted that several wells with data omitted on its map were confidential at the time the application was prepared.

3.2 Poco's Views

Poco stated that it derived net pay using cutoffs of 12 per cent density-porosity and 50 per cent on the Gamma Ray log. It indicated that the reservoir sand in the well in Lsd 3-6-37-15 W4M (the 3-6 well) and in the 2-11 well correlated with other wells in the pool and were therefore included in the pool.

3.3 Altex Group's Views

The Altex Group stated that it did not totally agree with the pool outline as supplied by Ranger. It suggested that the list of wells included in its intervention should comprise the pool and that undrilled sections on the perimeter of the pool should not be included.

3.4 Wainoco's Views

Wainoco indicated that Ranger's net pay map required some modification. Specifically, it suggested that wells in Lsds 13-14-36-15 W4M, 11-24-36-15 W4M, and 11-1-37-16 W4M should not be included since they did not contain recognizable Hackett sand gas pay. It also indicated that the 3-6 well, although geologically correlatable with the pool, appears to be a separate pool as suggested by pressure measurements. Wainoco added that the 2-11 well does not belong in the pool since the pay zone appears to be stratigraphically different and does not correlate to the Hackett sand in the main pool. Wainoco also contended that, although the 6-35 well tested gas on a DST, it should not be included in the pool. It suggested that, considering the large DST interval, the gas recovery may have been from the Detrital or Mississippian zones. It further submitted that the completion report for the well indicated a gas rate too small to measure after fracturing of the Hackett sand. Wainoco therefore disagreed with Ranger's contention that, at a porosity of 10.5 per cent, the Hackett sand in the 6-35 well could be productive. As a result, Wainoco contended that a 12 per cent density porosity cutoff is more indicative of pay in a commercial well.

3.5 Board's Views

With regard to the establishment of an appropriate density-porosity cutoff for the pool, the Board notes that Ranger and the Altex Group have applied a 10 per cent cutoff. Wainoco has presented evidence that 10 per cent appears too low as indicated by the lack of productivity of the 6-35 well. It is the opinion of Wainoco and Poco that a 12 per cent cutoff is reasonable; however, it should be noted that no specific evidence was presented to support a 12 per cent cutoff.

The Board has reviewed the Hackett sand test data for wells in the pool in conjunction with average porosities and notes that no well with an average density-porosity of less than 15 per cent has displayed proven capability. The Board suggests, therefore, that 15 per cent is an appropriate cutoff for the B Pool.

The Board believes that wells around the perimeter of the pool which have not demonstrated gas potential by favourable test results or definitive log characteristics should be excluded from the pool. The Board agrees with Wainoco that the Hackett sand pressure at the 3-6 well appears anomalous from that of other wells and therefore the well is likely in a different pool. With respect to the 2-11 well, the Board also concurs with Wainoco that the well is likely not part of the pool since the pay zone in this well appears to correlate best with a zone stratigraphically above the Hackett sand.

As a result of evidence presented, the Board proposes that the pool outline be amended as shown in Figure 1.

4 NEED FOR AN ORDER

Figure 2 is a well plat for the portion of the pool in which drainage is alleged. It shows the Ranger lands and its wells, and those of offset producers.

4.1 Ranger's Views

Ranger said that static gradient pressure measurements taken on the 16-12 well in September 1984 and in April 1985 showed that the reservoir pressure at the well had declined by 466 kilopascals (kPa). It submitted that this pressure loss equates to a reduction in marketable gas reserves from the B Pool of about 8.5 x 10^6 m^3. Ranger

stated that this reduction of reserves had been caused mainly by production from a well in Lsd 12-7-36-15 W4M (the 12-7 well). It also stated that inequitable drainage of reserves is occurring from section 14 and estimated the amount of drainage to November 1984 to be about 6.5×10^6 m^3.

Ranger indicated that several wells in the area of its lands were producing at high rates. These included the 12-7 well and wells located in Lsd 15-9-36-16 and Lsd 8-16-36-16 W4M (the 15-9 and 8-16 wells), the three of which produced 41 per cent of the total gas produced from the B Pool in 1984. Ranger submitted that drainage has likely been intensified with wells in Lsd 14-18-36-15 W4M (the 14-18 well) and in Lsd 1-13 and Lsd 4-15-36-16 W4M (the 1-13 and 4-15 wells, respectively) having been recently placed on production from the B Pool. It stated that all of these wells offsetting its lands are producing at a rate of take in excess of a 1 to 4850 ratio of flow rate to reserve, with some rates being as high as a 1 to 700 ratio, reflecting a 2-year producing life.

The applicant further stated that its 13-10 well produced at a rate of take of 1 to 10 639 in 1984. Ranger calculated this rate using an initial marketable reserve for section 10 of approximately 141.5×10^6 m^3 and a daily production rate of about 13.2×10^3 m^3. This latter is the daily rate assuming the well produced the entire year and does not consider shut-in periods.

Ranger stated that it has not had a reasonable opportunity to produce its share of gas from the B Pool. It said that operators of wells offsetting its lands have the flexibility of producing gas from the wells to industrial markets to "top-up" the reserves-based contracted volumes and, therefore, the rate of take for these wells is substantially greater than for Ranger's well. Ranger stated that it took steps to enter into "top-up" contracts but decided that without a method in place of sharing production with offset producers, only a small amount of drainage could be eliminated.

Ranger also said that it would have had to tie in currently shut-in wells on its lands in order to take full advantage of industrial markets and had decided to leave the wells shut in in order to conclusively prove that drainage was occurring. Ranger further stated that some of the contracts offered to it were declined because the price was not acceptable to it or its partners.

Ranger indicated that it had requested that Pan-Alberta allow it to produce gas from its contracted lands in excess of its DCQ so that it could sell to industrial markets. Pan-Alberta declined to give Ranger a written reply, although it verbally agreed to allow Ranger to sell gas to non-competitive (to Pan-Alberta) markets.

Ranger stated that it had met with offsetting producers and proposed a method of sharing the total pool production amongst the "capable" wells (wells which tested gas in excess of 1.4×10^3 m^3/d) in the pool. It stated that all parties were in general agreement with the proposal except Poco. It was this inability to negotiate a reasonable pool withdrawal rate which forced Ranger and its partners to request that the Board issue a rateable take order for the B Pool. Ranger said that even though it had declined some contracts due to price, it believed that markets exist and it will attempt to sell gas in excess of the Pan-Alberta contract to increase production from its lands if the Board issues an order limiting total pool withdrawals.

Ranger submitted that the only complete solution to the problem of inequitable drainage of lands in the B Pool is unitization. It said, however, that with the current high rates of withdrawal from the pool an interim method of sharing production is necessary. It also said that a rateable take order would have more permanence than a negotiated short-term agreement and would enhance efforts towards unitization of the pool.

Ranger concluded that it has adequately fulfilled the requirements of section 23 of the Act by proving that drainage is occurring from its lands and by pursuing markets to alleviate drainage.

4.2 Poco's Views

Poco suggested that when production is taken from a well in a large reservoir, such as the B Pool, some pressure drop at wells in close proximity to the producing well would occur even though the gas migration would be minimal. It stated that the only accurate method of determining current pressures in the pool would be to shut in the entire pool.

Poco said it did not know whether or not drainage is occurring from beneath Ranger's lands. Poco stated that as long as markets for the gas are available and no damage to the reservoir is occurring, production rates from a pool should not be limited by regulation.

Poco stated that it is producing its wells around Ranger's lands at high rates due to the deliverability of the wells. Poco contended that it had demonstrated that its policy is to maximize cash flow and not to cause drainage of offsetting lands, by offering Ranger a share of Poco's industrial contracts and capacity in its gas plant. Poco said it is not willing to cut back production rates from its wells offsetting Ranger's lands and does not believe the Board should be involved in determining rates unless the reservoir is being damaged.

Poco stated that it is required, pursuant to its gas purchase contract, to dedicate its reserves to TCPL which nominates gas on a 1 to 7300 rate of take. To supplement this contract, Poco said it enters into short-term intra-Alberta gas purchase contracts with industrial

buyers. It added that it has no limitations from TCPL on "topping-up" its contract except TCPL must approve the volumes and purchaser of additional gas. Poco further stated that it is not cross-dedicating reserves from other pools to the B Pool.

Poco said it offered Ranger a share of its contracts and capacity in its gas plant following completion of the 16-12 well in the B Pool; however, Ranger declined the offer and shut in the 16-12 well. Poco stated that since November 1984, when it was advised of Ranger's intent to file a rateable take application for the B Pool, only one meeting was held where Ranger proposed rate limitations on wells offsetting its lands. Poco did not accept the proposal and made a counter-proposal which Ranger refused. Poco concluded that Ranger has had, and continues to have, an opportunity to produce its fair and equitable share of pool reserves by utilizing the same opportunity as other producers to find markets for its gas. It further stated that Ranger has made no attempt to solve its drainage problems by selling additional gas, even up to its DCQ under the Pan-Alberta contract.

Poco stated that unitization of the B Pool is progressing and could be finalized in the near future. It believed that the incentive to unitize could be eliminated if a rateable take order limiting production was issued. If a rateable take order was issued with no limit on production, Poco believed there would still be incentive to unitize because more effective operations are possible with unitization.

4.3 Altex Group's Views

The Altex Group acknowledged that there is currently a problem of inequitable withdrawal rates and probable drainage of reserves from lands in the B Pool. It stated that Ranger has not taken advantage of available opportunities to sell additional gas to remedy the drainage situation and contends that the application for a rateable take order is unnecessary. It submitted that a company can protect its interests by acquiring contracts and producing gas to match rates of offsetting wells. It said that, as a partner in the Ranger lands, it initiated the drilling of the 16-12 well for the purpose of placing the well on production in an attempt to alleviate the drainage caused by offset production.

The Altex Group submitted that a negotiated solution to the drainage problem is available to at least minimize drainage from Ranger's lands, as indicated by the willingness of it and Poco to share contracts with Ranger. It further submitted that it would prefer a negotiated settlement rather than have the Board set rates, since rates which are too low would force operators to forego contracts which may have been difficult to obtain.

The Altex Group suggested the application should be denied because it believes Ranger has not been deprived of the opportunity to obtain its equitable share of pool production but has refused to accept contract offers.

The Altex Group stated that unit negotiations had been ongoing for about a year and it does not expect a unit to be finalized for at least an additional year.

4.4 Wainoco's Views

Wainoco stated that Ranger has conclusively demonstrated that drainage from Ranger's lands is occurring. It said that operators should not be permitted to produce wells at high rates without regard for possible drainage from other lands. Wainoco further stated that a company such as Ranger should have a reasonable opportunity to recover the reserves underlying its lands. It therefore supported Ranger's request of the Board to issue a rateable take order for the B Pool.

Wainoco stated it does not believe that pursuing contracts is an issue in this case; however, it did note that Ranger did not contact it with regards to sharing contracts.

Wainoco said it has not been involved in unit negotiations since January 1985 and does not see a unit being formed for at least a year and possibly 3 years.

4.5 CWNG's Views

CWNG did not comment on whether or not drainage is occurring. It made the assumption in its comments that the Board would find that there is drainage of B Pool reserves from beneath Ranger's lands. CWNG submitted that Ranger proposed a settlement with a 1 to 4500 ratio of rate of take which was agreed to by all parties with the exception of Poco, and that Poco was being unreasonable in not accepting the settlement.

CWNG had no comment on whether or not a market exists for the B Pool gas or the effect a rateable take order could have on unit negotiations.

4.6 Board's Views

The Board recognizes that the rateable take actions provided for in section 23 of the Oil and Gas Conservation Act are serious ones in that they result in the overriding of contracts which were freely negotiated by various private parties. It therefore believes that actions should not be taken under this section unless it is clear, with respect to a particular pool

- that each owner has not been afforded "the opportunity of obtaining his share of the production" of gas from the pool, and
- there is no reasonably acceptable alternative way, short of action by the Board, that such an opportunity can be provided.

The Board believes the test in these respects should be a strenuous one, and that the onus should be on the party

seeking an action by the Board to demonstrate the lack of opportunity and of alternative solutions.

In dealing with the need for a rateable take order in the specific case before it, the Board is of the view that the following questions should be addressed:

1 Has drainage of gas from beneath the Ranger lands occurred subsequent to the completion of a well on the applicant's property? Is drainage now occurring? Is drainage likely to continue to occur in future?

2 Are markets available to Ranger that would represent a reasonable opportunity for it to produce gas at rates more or less in proportion to its recoverable reserves and those elsewhere in the pool?

3 Should the state of current negotiations towards a unit influence the Board's decision with respect to the need for an order?

Drainage

Ranger's evidence suggests that drainage of B Pool reserves underlying its lands is occurring as a result of high withdrawal rates at wells offsetting Ranger's lands. The Altex Group and Wainoco agreed with Ranger that inequitable drainage of reserves is occurring in the pool but gave no evidence as to the extent of the drainage. CWNG appeared to assume that drainage was occurring.

Table 2 lists Ranger's producing wells and those offsetting its lands, along with the licensees, current withdrawal rates, and approximate rate/reserve ratio. The withdrawal rates are the average over the period 1 December 1984 to 30 April 1985. The rate/reserve ratio reflects the Board's current interpretation of the pool and the initial recoverable reserves underlying the drilling spacing unit of each well.

The Board finds from its examination and interpretation of the evidence, particularly the pressure data on the 16-12 well, that gas reserves underlying the applicant's lands are being drained by production from offsetting wells. The Board believes that drainage from beneath the 16-12 well occurred during the period from September 1984 to April 1985, as supported by pressure data submitted at the hearing. On the basis of the withdrawal rates shown in Table 2, particularly for the 12-7 and 1-13 wells, the Board believes the drainage was in the direction away from the Ranger lands. The Board further believes that drainage is occurring now and will continue in future unless producing rates at relevant wells are better balanced.

Markets

No evidence was put forward at the hearing to suggest that there are not markets available to Ranger which would allow it to produce greater volumes of gas than is currently the case. Ranger's own evidence indicated that if an order is issued limiting total withdrawals in accordance with its application, it would go out and find additional markets to allow it to increase its production. The additional gas would go to the discount intra-provincial market but there was no evidence from Ranger that production to serve such a market, to "top-up" the volumes going to the export market, would be uneconomic.

In addition to the above evidence from Ranger, Poco said that it had offered to share its "top-up" contract with Ranger. The existence of the offer was not disputed by Ranger, nor did it argue that such a market would be uneconomic.

On the basis of the above-mentioned evidence, the Board concludes that Ranger has had and continues to have reasonable opportunities to contract for the delivery of additional volumes of gas to markets, the service of which would not be uneconomic. For this reason, the Board is not prepared at this time to issue an order even though it has found that drainage is occurring and is likely to continue. Rather, it will defer final decision on the need for an order to provide Ranger with additional time to go out and attempt to contract for further sales of gas. If Ranger is unsuccessful in contracting for sufficient sales to allow producing rates more or less in proportion, on a reserve basis, to those from offsetting lands, the Board would expect it to submit further evidence documenting the situation. The Board would at that time review the matter by reopening the hearing if necessary, and decide if an order should be issued.

Ranger based part of its position on the suggestion that the withdrawal rates from offsetting wells were so great that even if contracts were available to it, the producing rates should be reduced. It argued that some of the wells were being produced at a rate which reflects a producing life of 2 to 4 years and that this was unreasonable in terms of the appropriate planning for the payout of investments. It, however, did not present evidence showing that such producing rates would make the investments uneconomic.

The Board's view is that it should limit rates of withdrawal only if required for conservation reasons or if absolutely necessary to prevent drainage. Ranger presented no evidence regarding the former concern.

If Ranger is unsuccessful in obtaining markets to rectify the drainage and comes back to the Board for an order, and if it is then basing its case in whole or in part on this question of "unreasonably high producing rates", the Board would expect to see evidence demonstrating that producing at such rates would not be an economically sound approach to depleting the pool.

Respecting the high withdrawal rates from certain wells offsetting the Ranger lands, as set out in Table 2, the Board notes that some of the rates are very high relative to reserves. It is concerned that these withdrawal rates could be "high-grading" production from the reservoir by taking only the gas from the most permeable parts of it. Drainage of gas from the tighter sections, which would take more time, might then be rendered uneconomic. This would mean a conservation loss in terms of total recovery from the pool. Because of this concern, the Board is asking its reservoir staff to review the matter in greater detail. If found necessary, the Board will impose a maximum daily withdrawal rate on wells in the pool for conservation purposes. This work will be carried on independent of any further request on the part of Ranger for a rateable take order.

Unit Negotiations

The evidence indicated that negotiations towards a unit have been going on for some time. There were widely differing views as to the prospects of one being formed in the near future. The Board believes that unitization of the pool would be the best overall solution to the current problem and would provide the most economic manner of depleting the reserves. It is therefore highly supportive of efforts towards a unit.

As stated in previous decision reports, the Board is reluctant to take actions, such as issuing a rateable take order, if it would influence and possibly prevent the formation of the unit. In this instance, because it is deferring a decision regarding the issuance of an order, there is no need at this time to address the question of the possible impact of such an action on unit negotiations.

5 DECISION

The Board defers action respecting Application 850010 to allow Ranger Oil Limited time to attempt to contract for additional volumes of sales which would allow it to produce its share of the production from the Maple Glen Upper Mannville B Pool.

DATED at Calgary, Alberta, on 24 May 1985.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

Antonio

H. Antonio, P.Eng.
Acting Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Ranger Oil Limited (Ranger) J. R. Smith A. A. Fradsham	L. W. Herrick, P.Eng. R. L. Solc, P.Eng. D. L. Solc
Altex Resources Ltd. Geocrude Energy Inc. Passburg Petroleums Ltd. (Altex Group) J. K. Farries, P.Eng.	E. H. Toews, P.Eng. of Altex Resources Ltd. L. G. Schnitzler, P.Eng. of Passburg Petroleums Ltd. D. K. Slessor of Altex Resources Ltd.
Canadian Western Natural Gas Company Limited (CWNG) W. A. Andreassen	
Poco Petroleums Ltd. (Poco) B. K. O'Ferrall	C. Stewart W. B. Haney, P.Eng. B. McLachlan
TransCanada PipeLines Limited (TCPL) P. J. Raina, P.Eng. V. H. Fifer	
Wainoco Oil & Gas Limited (Wainoco) I. F. Taylor	I. F. Taylor, P.Eng. D. Campbell, P.Eng. B. Rypien
Energy Resources Conservation Board staff C.J.C. Page M. S. Craig K. I. Fisher, C.E.T. C. D. Hill	

TABLE 2 PRODUCING WELLS ON OR NEAR RANGER'S LANDS

Well (Lsd-Sec-Twp-Rge W4M)	Licensee	Current Rate of Withdrawal[a] ($10^3 m^3/d$)	Current Average Rate/Producible Reserve Ratio
12-7-36-15	POCO	111	1/840
14-18-36-15	ALTEX GROUP	59	1/1500
1-1-36-16	POCO	9	1/10400
8-3-36-16	RANGER	25	1/4800
15-9-36-16	ALTEX GROUP	59	1/2300
13-10-36-16	RANGER	37	1/2300
1-13-36-16	POCO	132	1/1200
4-15-36-16	POCO	16[b]	1/11800
8-16-36-16	POCO	79	1/3600
3-22-36-16	POCO	51	1/2900
12-23-36-16	ALTEX GROUP	84	1/3500
7-24-36-16	POCO	64[c]	1/3200

[a] Average from 1 December 1984 to 30 April 1985.

[b] Shut in since February 1985.

[c] On stream January 1985.

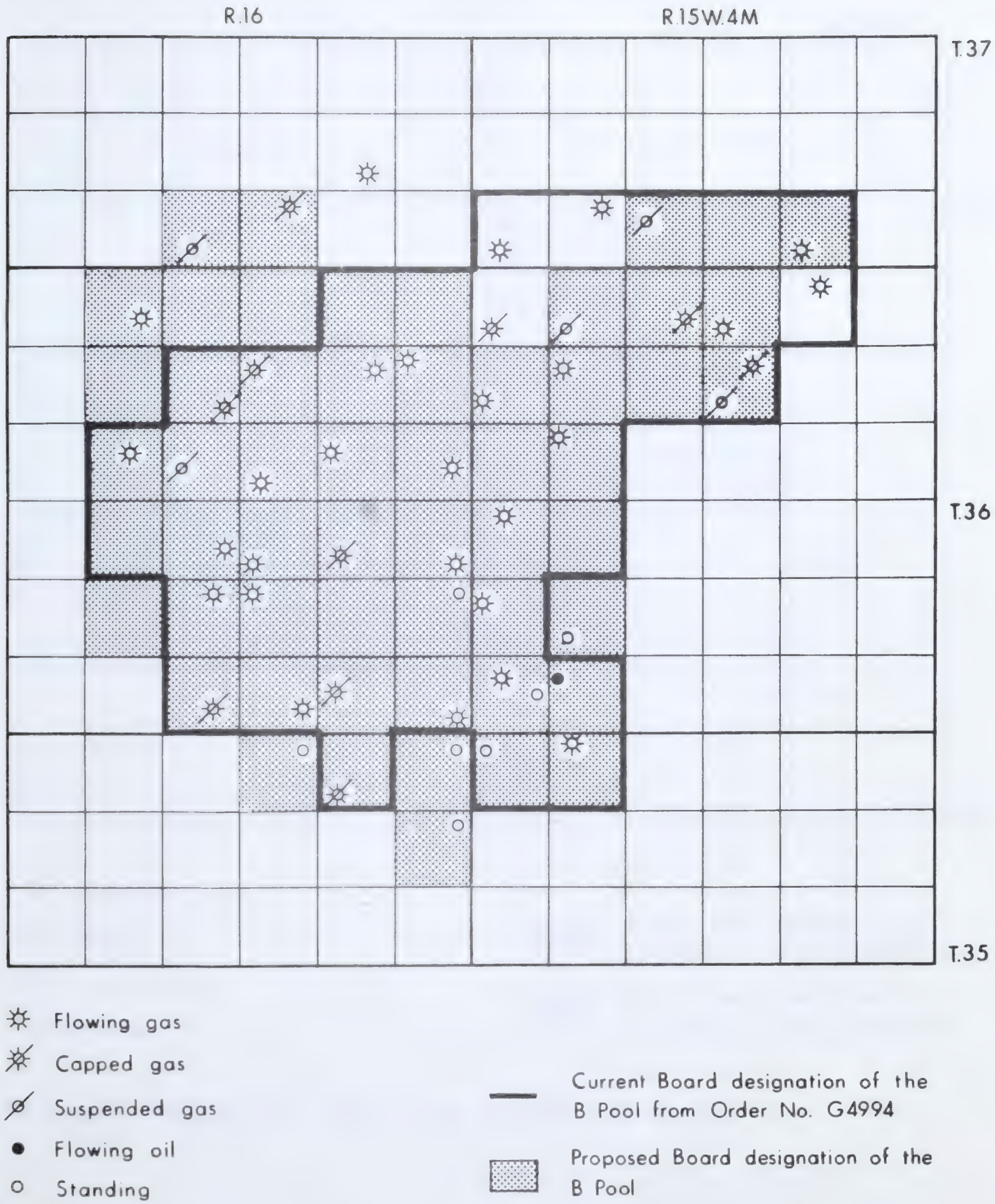


FIGURE 1 - MAPLE GLEN UPPER MANNVILLE B POOL

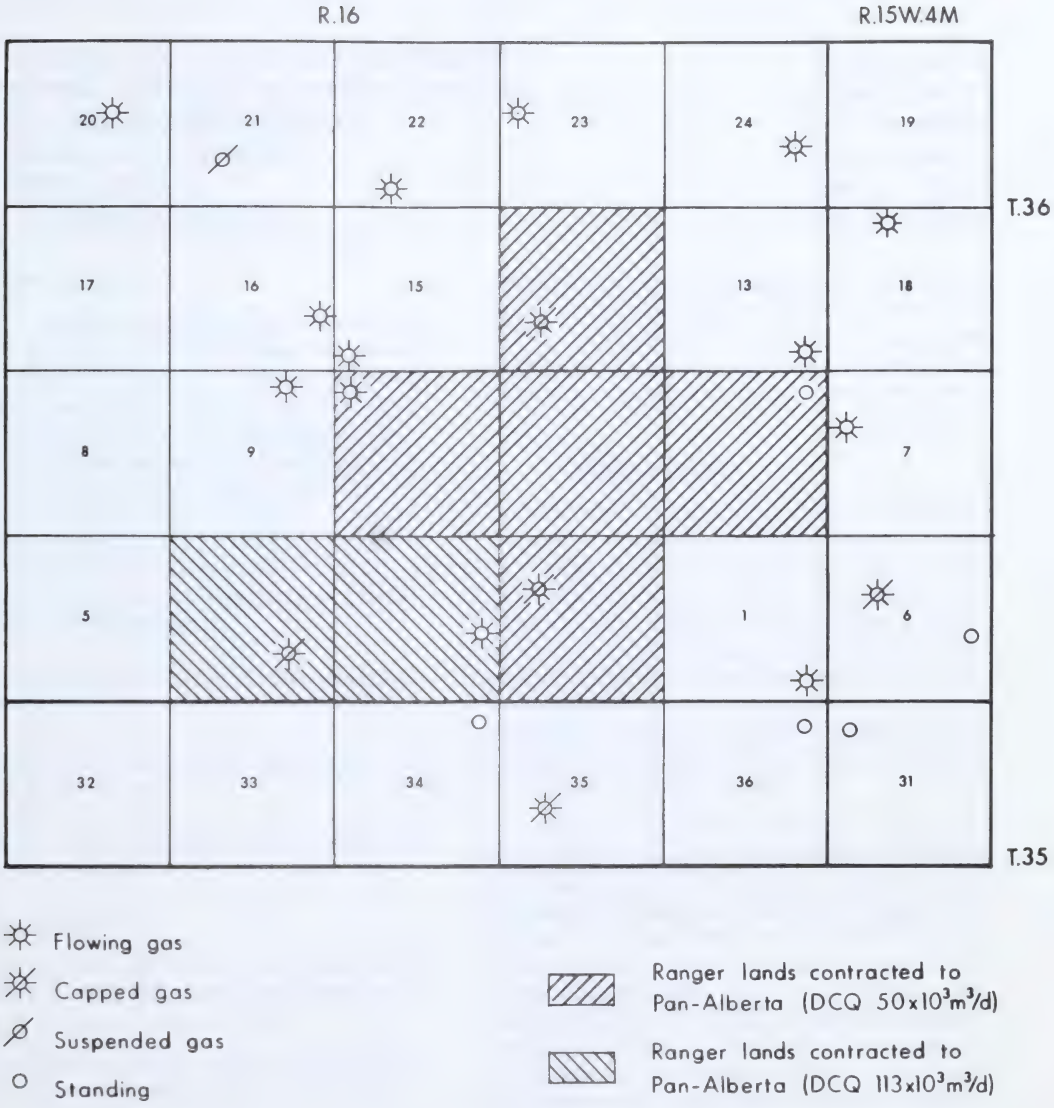


FIGURE 2 - RANGER'S LANDS AND OFF-SETTING WELLS

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATIONS FOR GAS REMOVAL PERMITS NORTHRIDGE PETROLEUM MARKETING, INC. SIGNALTA RESOURCES LIMITED TRICENTROL OILS LIMITED LAC MINERALS LTD. GASCAN RESOURCES LTD.

Decision D 85-24
Application 850226
Application 850250
Application 850251
Application 850252
Application 850253

1 APPLICATIONS

Northridge Petroleum Marketing, Inc. (Northridge) applied to the Energy Resources Conservation Board (Board), pursuant to section 2 of the Gas Resources Preservation Act (the Act), for five permits authorizing the removal of gas from Alberta. Northridge is a provincially incorporated company with head office in the City of Calgary, Alberta, and is acting on behalf of itself and Signalta Resources Limited (Signalta), Tricentrol Oils Limited (Tricentrol), Lac Minerals Ltd. (Lac), and Gascan Resources Ltd. (Gascan), all of which, as "producers", have requested separate removal permits. The permits would, in aggregate,

- provide for the removal of 1 100 535 800 cubic metres (m^3) of gas,
- provide for the maximum annual removal of 550 296 020 m^3 of gas,
- provide for the maximum daily removal of 2 154 952 m^3 of gas.

The permits would also

- provide, in each case, for two-year permit terms commencing with the approval of the Minister of Energy and Natural Resources, and
- name certain fields, pools, and areas from which gas may be obtained for removal from the province.

The permits have been requested for the purpose of supplying gas to Sohio Chemical Company of Cleveland, Ohio, U.S.A. (Sohio) for use at its oil refinery and chemical manufacturing site at Lima, Ohio, and to Southeastern Michigan Gas Company of Port Huron, Michigan, U.S.A. (Southeastern) for general system storage supply. The applied-for gas volumes would originate from lands in Alberta in which the applicants own or control the gas together with other working interest owners. Northridge has stated that it would purchase gas for its share of commitments to the Sohio and Southeastern markets from Paramount Resources Ltd. (Paramount) and Maynard Energy Inc. (Maynard). The gas would be transported in Alberta by NOVA, AN ALBERTA CORPORATION (NOVA) to Empress, and by TransCanada PipeLines Limited (TransCanada) from Empress to the point of export near Emerson, Manitoba.

2 BACKGROUND

On 30 November 1984 Northridge submitted an application (841245) requesting gas removal permits on behalf of itself and several producers seeking to effect a short-term spot-sale of gas to Sohio; six permits were requested. On 7 March 1985, Northridge withdrew Application 841245 and changed the substance of its request to include a spot-sale to Southeastern and a reduction in the number of permits requested to five. The new Northridge application was registered under number 850226 and each of the remaining four permit requests were registered as listed above.

In a letter of 9 April 1985, Northridge informed the Board that with respect to its own application (850226) three companies originally intending to supply gas to Northridge were unable to provide letters releasing their reserves from existing permit holders, and that as a result of this amendment to the application Paramount and Maynard would supply all of the Northridge gas requirements. A "Notice of Filing" respecting the applications was published in Alberta's major newspapers on 1 May 1985. ConsoliGas Management Ltd. was the only respondent, merely identifying itself as an interested party.

3 ISSUES

Section 5(3) of the Act provides that the Board shall not grant a permit for removal of gas from the province unless in its opinion it is in the public interest of Alberta having regard for, among other considerations,

- the present and future needs of persons in Alberta,
- the established reserves and the trends in growth and discovery of reserves of gas in Alberta, and

- the expected economic costs and benefits to Alberta of the removal of the gas from Alberta.

The Board has concluded that the issues in the subject applications are

(a) Is the gas proposed for removal, surplus to Alberta's requirements?

(b) Would the economic costs and benefits of the proposed removal be in the public interest of Alberta?

4 IS THE GAS SURPLUS TO ALBERTA'S REQUIREMENTS?

4.1 Applicant's Views

The applicants stated that the applied-for volumes are surplus to Alberta's 25-year requirements, including permit related fuel and shrinkage, remaining permit commitments, and permits pending Order in Council.

4.2 Board's Views

The Board notes that with the exception of Lac, which has applied for a permit to remove 222 939 860 m^3 of gas, all of the applied-for removal volumes are included in existing removal permits for which release documents have been submitted. The Board's estimate of reserves available to Lac in the areas which are not included in existing removal permits is 1593 million cubic metres (10^6 m^3), some 1370 x 10^6 m^3 more than the total amount applied for by Lac.

The Board is satisfied that the aggregate volumes of gas for which removal permits are requested will be available to the applicants, and that the gas is surplus to Alberta's requirements.

5 ARE THE ECONOMIC COSTS AND BENEFITS IN THE ALBERTA PUBLIC INTEREST?

5.1 Applicants' Views

The applicants stated that the proposed gas removals would be incremental and in the public interest. They also stated that economic benefits to Alberta would be maximized by increasing total sales of Alberta gas, since 78 to 80 per cent of the applied-for volumes are currently committed to removal permits which are not being fully utilized. The proposed new sales would be interruptible in nature, allowing producers to divert only those volumes not taken under existing contract commitments. They also stated that the remaining 20 to 22 per cent of the total applied-for volume represents gas currently being sold in Alberta at discount prices.

Economic statements provided in the applications indicate that significant positive contributions to the Alberta Export Flow-back Price Adjustment Fund would result from the proposed sales.

5.2 Board's Views

The Board believes that the key questions to be addressed in assessing the matter of economic costs and benefits are

- Whether the proposed sale would be incremental and would result in an increase in the total sales of Alberta gas.
- Whether the gas would be priced competitively with respect to competing fuels.
- Whether the netback to the Alberta border (the market price less transmission and other costs) would be reasonable in comparison to netbacks resulting from sales to other markets, with suitable transportation arrangements having been made.

The Board is satisfied that the proposed sales to Sohio and Southeastern represent largely new markets for Alberta gas, and would therefore result in an increase in the total sales of Alberta gas. The Board is also satisfied that in both proposed sales the gas would be priced competitively with respect to competing fuels, however, in order to ensure that reasonable net benefits would accrue to Alberta as a result of the sales, the Board believes that any permits issued to the applicants should be subject to the following conditions:

"In the event that the Alberta Border Price ceases to exist, the permit shall be suspended until the Permittee has filed a copy of the gas purchase contract specifying the purchase price for the gas and until the Board has advised the Permittee in writing that the removal of the gas at the specified purchase price will continue to be in the public interest of Alberta within the meaning of subsection 5(3) of the Act."

"The Permittee shall, promptly upon the execution thereof, file a copy of any document which changes the purchase price specified in the gas purchase contract and described in the present application, and this filing requirement shall apply to each successive change in the purchase price for the gas."

6 DECISION

In light of its findings and responsibilities under the Act, the Board, with the approval of the Minister of Energy and Natural Resources, is prepared to grant gas removal permits to Northridge, Signalta, Tricentrol, Lac, and Gascan, as requested in their current applications respecting Sohio and Southeastern. The permits would be in

the form shown in Appendix A and would be subject to the terms and conditions contained therein, as well as any conditions imposed by the Minister of Energy and Natural Resources.

DATED at Calgary, Alberta, on 19 June 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Northridge Petroleum Marketing, Inc. authorizing the removal of gas from the Province

PERMIT NO. NM 85-1

WHEREAS Northridge Petroleum Marketing, Inc. has applied in Application No. 850226 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Northridge Petroleum Marketing, Inc. is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Northridge Petroleum Marketing, Inc. (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 498 286 167 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 1 076 457 cubic metres and in a 12-month period such rates shall not exceed 249 284 722 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

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*This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Atlee-Buffalo	Liege
Avenir	Medicine Hat
Chard	Saleski
Coyote	Sounding

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipeline of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Signalta Resources Limited authorizing the removal of gas from the Province

PERMIT NO. SR 85-1

WHEREAS Signalta Resources Limited has applied in Application No. 850250 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Signalta Resources Limited is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Signalta Resources Limited (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 232 231 381 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 413 586 cubic metres and in a 12-month period such rates shall not exceed 116 115 690 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

*This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Beaverhill Lake	Killam North	Sedgewick
Birch	Mannville	Strome
Bruce	Medicine River	Ukalta
Donalda	Norris	Viking-Kinsella
Forestberg	Pembina	Warwick
Hairy Hill	Plain	Wavy Lake
Inland	Ranfurly	Whitford
Killam	Royal	Willingdon

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or 12, both in Township 20, Range 1, West of the 4th meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipeline of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Tricentrol Oils Limited authorizing the removal of gas from the Province

PERMIT NO. TO 85-2

WHEREAS Tricentrol Oils Limited has applied in Application No. 850251 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Tricentrol Oils Limited is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Tricentrol Oils Limited (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to thesaid Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 103 396 504 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 188 946 cubic metres and in a 12-month period such rates shall not exceed 51 698 252 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

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*This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Bentley	Rosalind
Gordondale	Watts

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipeline of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contract which specifies the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Lac Minerals Ltd. authorizing the removal of gas from the Province

PERMIT NO. LM 85-1

WHEREAS Lac Minerals Ltd. has applied in Application No. 850252 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Lac Minerals Ltd. is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Lac Minerals Ltd. (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 222 939 860 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 396 589 cubic metres and in a 12-month period such rates shall not exceed 111 469 930 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

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*This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Caroline	Retlaw	Ansell
Chain	Sundre	
Farrell	Benbow	
McLeod	Minehead	

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1), shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipelines of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Gascan Resources Ltd. authorizing the removal of gas from the Province

PERMIT NO. GR 85-1

WHEREAS Gascan Resources Ltd. has applied in Application No. 850253 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Gascan Resources Ltd. is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Gascan Resources Ltd. (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 43 454 860 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 79 374 cubic metres and in a 12-month period such rates shall not exceed 21 727 430 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

*This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Medicine Hat

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipeline of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contract which specifies the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy
Vice Chairman

CYANAMID CANADA INC. APPLICATION FOR GAS REMOVAL PERMIT

Decision D 85-25
Application 850254

1 APPLICATION

Cyanamid Canada Inc. (Cyanamid) applied to the Energy Resources Conservation Board (Board) pursuant to the Gas Resources Preservation Act (the Act), for a permit authorizing the removal of gas from Alberta. The applicant requested a permit which would

- provide for the removal of 124.028 million cubic metres (10^6 m^3) of gas, in total, during a 2-year permit term,
- provide for the maximum annual removal of 62.014 x 10^6 m^3 of gas,
- provide for the maximum daily removal of 212.377 thousand cubic metres (10^3 m^3) of gas, and
- name the Thornbury Field as a field from which gas may be obtained for removal from the province.

2 BACKGROUND

Cyanamid has proposed to purchase gas from Canadian Worldwide Energy Limited near Atmore, Alberta, on the NOVA, AN ALBERTA CORPORATION (NOVA) system. By arrangements with NOVA, TransCanada PipeLines Limited, and Consumers' Gas Company Ltd., Cyanamid proposes to transport the gas to Niagara Falls, Ontario, for use as feedstock and fuel in the production of ammonia. All of the gas would be produced from currently tied-in wells in the Thornbury Field; no additional gathering facilities would be required.

3 ISSUES

Section 5(3)(c) of the Act provides that the Board shall not grant a permit for removal of gas from the province unless in its opinion it is in the public interest of Alberta having regard for, among other considerations,

- the expected economic costs and benefits to Alberta of the removal of gas or propane from Alberta.

The Board has concluded that the principal issue in the Cyanamid application is whether or not the economic costs and benefits of the proposed gas removal are in the public interest of Alberta.

4 ARE THE ECONOMIC COSTS AND BENEFITS IN THE ALBERTA PUBLIC INTEREST?

The Board believes that the key questions to be addressed in assessing the matter of economic costs and benefits are:

- Whether the proposed sale would be incremental and would result in an increase in the total sales of Alberta gas.
- Whether the gas would be priced competitively with respect to competing fuels.
- Whether the netback to the Alberta border (the market price less transmission and other costs) would be reasonable in comparison to netbacks resulting from sales to other markets, with suitable transportation arrangements having been made.

5 APPLICANT'S VIEWS

The applicant stated that the applied-for removals would not displace sales of Alberta gas under existing long-term removal permits for three reasons:

- It has no contractual commitments to purchase natural gas from anyone that are currently in force and that extend beyond 1 June 1985.
- It has lost a considerable amount of money every year since the middle of 1981 in its nitrogen business segment, and projects that under existing gas pricing policies these losses should continue.
- Natural gas constitutes 80 per cent of its variable costs incurred in ammonia production.

The applicant went on to say that an effective reduction in its gas cost "could change this situation".

6 BOARD'S VIEWS

Since the price (at the Alberta border) of gas considered in the application is the same as would apply under other arrangements, the Board does not believe that there is an issue of reasonableness of netback or of competitiveness of price at the burner tip.

The Board believes that the important issue is the incrementality of the sale, and that for a sale to be incremental it must represent a delivery that would not otherwise occur.

The Board believes that where a proposed removal would preserve an existing market, there must be sufficient evidence to show that denial of the application would lead to the loss of the market and reduced deliveries of Alberta gas. The applicant's evidence on incrementality was limited to listing possible consequences of denial with no evidence as to the likelihood of the loss of markets. As a result, the Board does not have sufficient evidence to satisfy it that the use of interruptible gas by the applicant in the manufacture of ammonia and fertilizers produced from ammonia would be reduced or discontinued if the application were denied. The Board is therefore not able to conclude that the deliveries would be incremental.

7 DECISION

The Board's assessment of the application is that it is not in the public interest in that approval would not result in net benefits to Alberta. Therefore, the application does not satisfy the requirements of the Gas Resources Preservation Act and for this reason is denied. The denial is without prejudice to a subsequent application if the applicant can demonstrate that its proposal would result in incremental gas volumes moving to its manufacturing facilities.

DATED at Calgary, Alberta, on 13 June 1985.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

SIMPLOT CHEMICAL COMPANY LTD. APPLICATION FOR GAS REMOVAL PERMIT

Decision D 85-26
Application 841199

1 APPLICATION

Simplot Chemical Company Ltd. (Simplot) applied to the Energy Resources Conservation Board (Board), pursuant to the Gas Resources Preservation Act (the Act), for a permit authorizing the removal of gas from Alberta. The applicant requested a permit which would

- provide for the removal of 1550 million cubic metres (10^6 m^3) of gas, in total, during a 15-year permit term,
- provide for the maximum annual removal of 103 x 10^6 m^3 of gas,
- provide for the maximum daily removal of 354 thousand cubic metres (10^3 m^3) of gas,
- provide for the removal of gas not removed in any annual period during any of the following four annual periods during the term of the permit, subject to the maximum daily limitation, and
- name the Liege Field as a field from which gas may be obtained for removal from the province.

2 BACKGROUND

Under terms of a Farmin Agreement of October 1983, Simplot obtained an interest in the gas reserves for which it has requested a removal permit. Simplot proposes to use the gas in an expansion of its ammonia fertilizer plant located in Brandon, Manitoba. Since 1 May 1984, Simplot has been removing gas from the Liege Field pursuant to a Permit Usage Agreement with Pan-Alberta Gas Ltd. (Pan-Alberta). The Board acknowledged the Permit Usage Agreement between Simplot and Pan-Alberta in a letter to Pan-Alberta dated 19 April 1984.

3 ISSUES

The present application was received by the Board on 23 November 1984, shortly after the Legislative Assembly of Alberta enacted a new Gas Resources Preservation Act, to which Royal Assent was given on 13 November 1984. The new Act modified the requirements that must be satisfied before gas may be removed from the province.

Section 5(3)(c) of the Act provides that the Board shall not grant a permit for removal of gas from the province unless in its opinion it is in the public interest of Alberta having regard for, among other considerations,

- the expected economic costs and benefits to Alberta of the removal of gas or propane from Alberta.

The Board has concluded that the principal issue in the Simplot application is whether or not the economic costs and benefits of the proposed gas removal are in the public interest of Alberta.

4 ARE THE ECONOMIC COSTS AND BENEFITS IN THE ALBERTA PUBLIC INTEREST?

The Board believes that the key questions to be addressed in assessing the matter of economic costs and benefits are:

- Whether the proposed sale would be incremental and would result in an increase in the total sales of Alberta gas.
- Whether the gas would be priced competitively with respect to competing fuels.
- Whether the netback to the Alberta border (the market price less transmission and other costs) would be reasonable in comparison to netbacks resulting from sales to other markets, with suitable transportation arrangements having been made.

5 APPLICANT'S VIEWS

Simplot stated that it "cannot demonstrate that it would not purchase a significant part of its requirements under an existing Alberta gas removal permit if this application were denied since such a decision would have to be weighed in the light of Simplot's prevailing economic environment at the time". Simplot also stated a number of possible consequences of denial coupled with a decision by Simplot not to continue removing gas under the existing arrangement with Pan-Alberta. These include shut down of the ammonia plant, loss of U.S. markets, and lower crown royalties due to diversion of gas from Simplot to Alberta markets where lower prices may

prevail. Simplot noted that its decision to apply for its own removal permit and proceed with necessary contractual arrangements was made prior to the legislative changes to the Act.

The applicant stated that it is currently purchasing gas from itself and Paramount Resources Ltd., transporting it from the Liege Field to the Alberta border via NOVA, AN ALBERTA CORPORATION; removing it under Pan-Alberta's Permits PA 80-3 and PA 81-4 under a Permit Usage Agreement, and shipping it to the point of end use via TransCanada PipeLines Limited and Plains-Western Gas (Manitoba) Ltd. It described this arrangement under which gas has been transported to its plant since June 1984, as being "on an interim basis ... pending this application and the issuance of a gas removal permit".

6 BOARD'S VIEWS

Since the price (at the Alberta border) of gas considered in the application is the same as would apply under other arrangements, the Board does not believe that there is an issue of reasonableness of netback or of competitiveness of price at the burner tip.

The Board believes that the important issue is the incrementality of the sale, and that for a sale to be incremental it must represent a delivery that would not otherwise occur.

The Board believes that where a proposed removal would preserve an existing market, there must be sufficient evidence to show that denial of the application would lead to the loss of the market and reduced deliveries of Alberta gas. The applicant's evidence on incrementality was limited to listing possible consequences of denial with no evidence as to the likelihood of the loss of markets. As a result, the Board does not have sufficient evidence to satisfy it that the use of interruptible gas by the applicant in the manufacture of ammonia and fertilizers produced from ammonia would be reduced or discontinued if the application were denied. The Board is therefore not able to conclude that the deliveries would be incremental.

7 DECISION

The Board's assessment of the application is that it is not in the public interest in that approval would not result in net benefits to Alberta. Therefore, the application does not satisfy the requirements of the Gas Resources Preservation Act and for this reason is denied. The denial is without prejudice to a subsequent application if the applicant can demonstrate that its proposal would result in incremental gas volumes moving to its manufacturing facilities.

DATED at Calgary, Alberta, on 13 June 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION BY THE IMPERIAL PIPE LINE COMPANY, LIMITED TO CONSTRUCT A PIPELINE AND RELATED FACILITIES AND TO AMEND EXISTING LICENCES

Decision D 85-27
Applications 850350 850351 and 850352

1 THE APPLICATION

The Imperial Pipe Line Company, Limited (IPL) submitted applications to construct approximately 200 kilometres of 323.9-millimetre (mm) outside diameter (OD) pipeline and related facilities between Ellerslie and Sundre, as shown on the attached diagram, and to amend existing licences to increase the maximum operating pressure and to reverse the direction of flow on a line between the Strathcona refinery and Ellerslie, all to transport Cold Lake blended crude bitumen to Sundre.

The application was considered at a public hearing in Nisku, Alberta, on 11 June 1985, with N. A. Strom, P.Eng., L. A. Bellows, P.Eng., and F. J. Mink, P.Eng., sitting. Participants at the hearing are listed in the Appendix.

2 INTRODUCTION

The purpose of the proposed project is to provide a system of transportation to deliver crude bitumen production, currently being developed in the Cold Lake region, to the Exxon USA (Exxon) refinery in Billings, Montana.

The need to access this marketplace arises from two major factors. Firstly, there has recently been a crude-oil production shut-in situation in Alberta due partly to capacity restrictions on the Interprovincial Pipe Line Company system, which is a major shipper of crude oil. The restriction is due, in part, to the increasing supply of the higher viscosity heavy crude oils. IPL produced evidence of support for the construction of the applied-for facilities from the Alberta Petroleum Marketing Commission which emphasized the potential of the proposed pipeline system to alleviate capacity restrictions. The second factor influencing the necessity of this project is the new Federal/Provincial Government Western Accord Energy Agreement, resulting in expected crude oil export demand growth into the US marketplace, and more specifically, crude bitumen export growth in the US midwest marketplace.

3 THE PROPOSED PIPELINE SYSTEM

The purpose of the IPL proposed pipeline system is to transport 2385 cubic metres per day (m^3/d) of Cold Lake blended crude bitumen (blend) from Esso's Strathcona refinery in Edmonton to Sundre, at which point the blend will be accepted by the Rangeland Pipe Line Co. Ltd. system for transportation southward through the Continental Pipe Line Company's (Glacier) system to Exxon's refinery at Billings, Montana.

IPL stated that it had investigated other transportation routes but that the proposed system was the most feasible. For the proposed volumes only minor modifications will be necessary to the Rangeland and Glacier systems and the additional volumes in these systems will not displace other transported volumes.

IPL indicated that it will be able to obtain sufficient volumes of diluent for the approximately 28 per cent dilution ratio required. It stated that Exxon would purchase the blend and that it had no immediate plans to return any of the diluent to Alberta.

While IPL optimized the pipeline diameter for the applied-for volumes, it stated that by adding two pump stations the capacity of the line could be doubled to 4750 m^3/d and possibly increased to 7950 m^3/d by also upgrading the existing stations. However, IPL stated that significant expansions to facilities on the Rangeland and Glacier systems would be necessary to accommodate any substantial increase over the proposed 2385 m^3/d. Though it has no immediate plans to upgrade, it recognizes that future market prospects may well result in expansion of the pipeline.

IPL confirmed that the leak prevention and detection standard would be in accordance with the Canadian Petroleum Association Recommended Practice for Liquid Petroleum Pipeline Leak Prevention and Detection, and that an internal electromagnetic survey of the pipeline will be performed shortly after commissioning the system. IPL identified five minor route changes requested and agreed to by landowners.

The Board is satisfied that there is a need for the pipeline and believes that it will help to alleviate a shut-in crude oil problem in Alberta. It is also satisfied that the design of the pipeline meets all the requirements of the Pipeline Act and Regulations. The Board accepts the minor route changes and in particular notes that a change in the north-west quarter of section 8 and the northeast quarter of section 7 in township 50, range 24, west of the the 4th meridian (NW 1/4 Sec 8 and NE 1/4 Sec 7-50-24 W4M), introduced at the beginning of the hearing, resulted in the withdrawal of an intervention by a group of landowners.

4 INTERVENTIONS

4.1 Daon Development Corporation (Daon)

As a principal planning consultant of the Ellerslie industrial area traversed by the proposed pipeline, Daon suggested a modified routing in Sec 17-51-24 W4M which it believed would reduce the impact on future development plans. Daon stated that the pipeline in the IPL preferred route could interfere with the location of services, roads, and railways contemplated in the Ellerslie area structure plan. Daon's main concern was that the current landowners and potential users should not experience serious access problems when urban development proceeds.

IPL pointed out that Daon was not the owner of the lands on which the modified routing was suggested and stated that IPL had obtained the agreement of the current owners for its preferred route. It indicated that Daon's proposed modification would involve two additional crossings of 41 Avenue to avoid a farmstead and an antenna station. IPL stated that it had held some discussions with Daon and was willing to negotiate further with Daon to accommodate site-specific development plans along the proposed route.

The City of Edmonton noted the IPL routing may place constraints on future subdivision and development for medium industrial uses. However, it did not see serious conflicts and considered agreement by the current landowners as a confirmation of that.

On the evidence submitted, the Board cannot assess the significance of the impact of the preferred route on Daon's development plans, but notes the willingness of IPL to negotiate with Daon to accommodate site-specific problems. Considering the absence of any objections by the current landowner and that the City of Edmonton has no objection, the Board accepts IPL's preferred route.

4.2 Edmonton Broadcasting Co. Ltd. (Edmonton Broadcasting)

Edmonton Broadcasting drew attention to the three 10-metre (m) rights of way (IPL's with three pipelines in one 10-m right of way and Texaco Exploration Canada Ltd.'s (Texaco) with one pipeline in each of two 10-m rights of way) traversing the west side of 12 hectares (30 acres) of land it owns at the corner of Nisku Spine Road and Ellerslie Road in Edmonton. Addition of the applied-for right of way would further reduce the area available for future development of the 12 hectares. To limit further pipeline encroachment, Edmonton Broadcasting suggested that the applied-for pipeline be installed within one of the parallel adjoining Texaco rights of way. It contended that Texaco's refusal to accept IPL's request for access to those rights of way lands did not by itself represent a sound basis for requiring that Edmonton Broadcasting be compelled to provide additional right of way for the new IPL pipeline.

IPL indicated that in recognition of the potential for future urban development it had reduced its right of way width in the area in question from the desired 25-m width to only 10-m width. IPL further noted that its existing 10-m easement already has three pipelines, one of which is a high vapour pressure pipeline. Also, it noted that an existing pipeline surface facility on the Texaco right of way would have to be avoided. Therefore, for safety reasons and on a practical basis, IPL stated that it would be imprudent to add a further pipeline to the existing rights of way.

The Board concludes that installation of the proposed pipeline on an adjoining easement would be difficult, though not impossible. On balance, the Board believes that the most reasonable approach would be to minimize potential conflict with future surface developments on the Edmonton Broadcasting lands by placing the IPL pipeline as near to the adjoining Texaco 10-m right of way as is safely possible. To this end, the Board will require additional detailed information from Texaco respecting the exact location of its pipeline within its easement and will specify where the IPL pipeline is to be placed.

5 DECISION

The Board approves Applications 850350, 850351, and 850352 by Imperial Pipe Line Company, Limited along the preferred route indicated in the applications, with the minor route modifications presented by IPL to the Board at the hearing, and is prepared to issue the necessary permits.

The Board will specify the location of the applied-for pipeline within the easement through the property of Edmonton Broadcasting upon receipt of information from Texaco, and will condition the permit to this effect.

The approving documents will be issued subject to the above condition and subject to receipt of the approval of the Minister of the Environment respecting environmental matters as set out in section 8 of the Pipeline Act.

ISSUED at Calgary, Alberta, on 19 June 1985.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Board Member

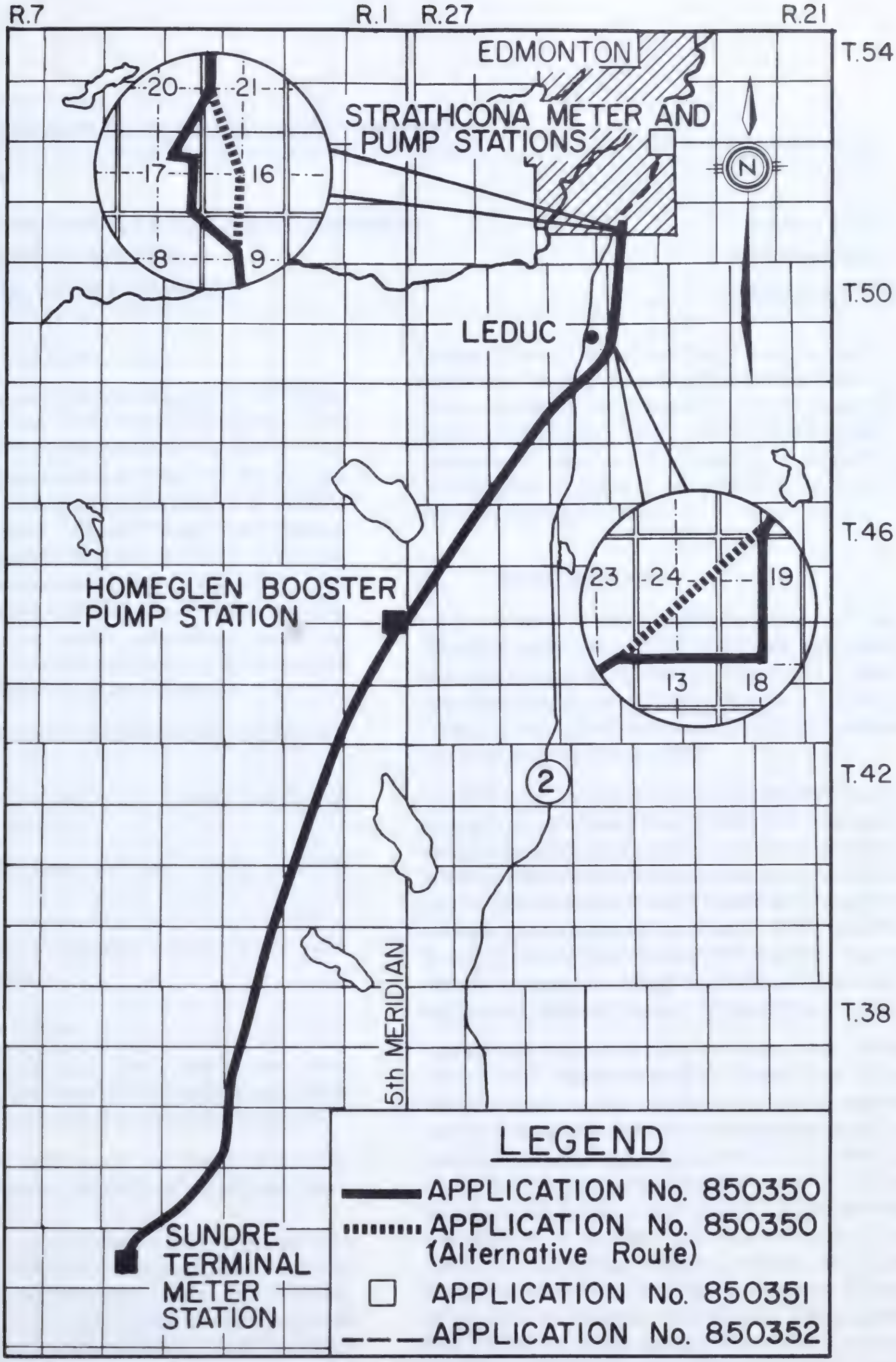
L. A. Bellows, P.Eng.
Board Member

F. J. Mink, P.Eng.
Acting Board Member

APPENDIX

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Imperial Pipe Line Company, Limited (IPL) D. G. Hart, Q.C.	R. A. Hill, P.Eng. G. A. Barnet J. G. Hutcheson, P.Eng. R. W. Peddie, P.Eng. (Canuck Engineering Ltd.) D. L. Johnson (Hardy and Associates (1978) Ltd.)
Home Oil Company Limited C. A. Keck	
Dome Petroleum Limited D. A. Holgate	
Edmonton Broadcasting Co. Ltd. (Edmonton Broadcasting) K. D. Wakefield	T. Strain
Daon Development Corporation (Daon) L. Spencer	P. A. Ford L. Spencer
The City of Edmonton W. Cameron	W. Cameron
D. Cruden, D. Bilsborrow, M. Bilsborrow D. Friedenberg, R. Paradis D. B. Roth	
Alberta Environment staff D. L. Bratton	
Energy Resources Conservation Board staff H. R. Hansford A. Cassley, P.Eng. D. Fraser T. J. Pesta, P.Eng.	



THE IMPERIAL PIPE LINE COMPANY, LIMITED
APPLICATIONS NO. 850350, 850351, 850352.
ELLERSLIE-SUNDRE AREA

D 85-27

ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION FOR GAS REMOVAL PERMITS POCO PETROLEUMS LTD. TRICENTROL OILS LIMITED

Decision D 85-28
Application 850140
Application 850144

1 APPLICATIONS

Tricentrol Oils Limited (Tricentrol) and Poco Petroleums Ltd. (Poco) applied to the Energy Resources Conservation Board (Board), pursuant to section 2 of the Gas Resources Preservation Act (the Act), for separate gas removal permits to supply gas to the J. R. Simplot Company (Simplot) at Grand Forks, North Dakota. Both permits would be for removal of gas from Alberta for Simplot, notwithstanding the fact that Tricentrol has the agreement with Simplot. Tricentrol would purchase Poco's gas on the Saskatchewan border and sell it to Simplot, with its own share of the market, at Emerson, Manitoba. Each permit would

- provide for the removal of 30 850 000 cubic metres (m^3) of gas,
- provide for the maximum annual removal of 15 400 000 m^3 of gas,
- provide for the maximum daily removal of 42 300 m^3 of gas.

The gas would be delivered under a best-efforts, interruptible basis.

The permits would also

- provide, in each case, for 2-year permit terms commencing on 1 July 1985 or within a reasonable time beyond that date if approvals are delayed,
- name certain fields, pools, and areas from which gas may be obtained for removal from the province.

The applied-for gas volumes would originate from lands in Alberta in which the applicants own or control 100 per cent of the gas together with other working interest owners. The gas would be transported in Alberta by NOVA, AN ALBERTA CORPORATION (NOVA) to Empress, and by TransCanada PipeLines Limited (TransCanada) from Empress to the point of export near Emerson, Manitoba. Simplot would arrange for transportation from Emerson to its food processing plant in Grand Forks, North Dakota. Transportation arrangements have been confirmed by all connecting carriers from the point of production to the Simplot plant gate in North Dakota.

2 BACKGROUND

On 11 February 1985 and 12 February 1985 Poco and Tricentrol, respectively, submitted separate applications requesting gas removal permits to provide a short-term interruptible sale of gas to Simplot. A Notice of Filing respecting the Poco and Tricentrol applications was published on 25 April 1985.

ConsoliGas Management Ltd. (ConsoliGas) made a submission to the Board dated 8 May 1985. The Board determined that the nature of the comments contained in that submission did not demonstrate that ConsoliGas may be directly and adversely affected by a favourable decision on the applications. Based on this fact, the Board, in a letter dated 24 May 1985, notified ConsoliGas that it was processing the Poco and Tricentrol applications without regard to ConsoliGas position.

ConsoliGas then filed a further submission, dated 30 May 1985, which contended among other things that the proposed sale would not be an incremental sale of Alberta gas. In view of the seriousness of the contention the Board decided, pursuant to section 42 of the Energy Resources Conservation Act, to review its previous decision on the ConsoliGas submission as described in its 24 May 1985 letter to ConsoliGas. Therefore, the applications were heard by the Board at a public hearing held in Calgary, Alberta, on 20 June 1985, with V. Millard, F. J. Mink, P.Eng., and H. J. Webber, P.Eng., sitting. The following table provides a list of those who appeared at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Tricentrol Oils Limited (Tricentrol) R. E. Nowack	Y. L. Mah D. H. Hawke of J. R. Simplot Company
Poco Petroleums Ltd. (Poco) J. D. Rooke	C. W. Stewart
Consolidated Natural Gas Limited and ConsoliGas Management Ltd. (ConsoliGas) H. M. Kay	
Independent Petroleum Association of Canada (IPAC) A. S. Hollingworth	R. G. Dewolf R. V. Hillary E. R. Elenko
TransCanada PipeLines Limited (TCPL) L. W. Sloan	
Energy Resources Conservation Board staff M. J. Bruni G. A. Habib	

Submissions were received from ConsoliGas, the Independent Petroleum Association of Canada (IPAC), and TransCanada. None of the interveners opposed the applications and only IPAC submitted evidence on matters relating to the applications.

3 ISSUES

Having regard for the new Gas Resources Preservation Act, the Board has concluded that the issues in the subject applications are:

- Is the gas proposed for removal, surplus to Alberta's requirements?
- Would the economic costs and benefits of the proposed removal be in the public interest of Alberta?

4 VIEWS OF THE APPLICANTS

The applicants contended that the applied-for volumes are available to them for removal and are surplus to Alberta's requirements. None of the interveners contested that position.

The applicants also stated that the proposed gas sales would be incremental and that removal would be in the public interest. Currently, Simplot uses fuel oil as the primary fuel and therefore, the proposed gas removals would not displace Alberta gas moving under existing removal permits. In responding to questions respecting alternative sources of energy supply in case the application was not approved, Mr. Hawke of Simplot stated that the plant would seek United States (U.S.) source gas available on the spot market. He also noted that Simplot is investigating the feasibility of using coal for fuel at plants in the North Dakota area. The results of that study will not be available for some time.

The applicants argued that the proposed contract price at the Canada/U.S. border is appropriate, having regard for the price of alternative sources of energy which in their views are U.S. spot gas sales and coal. The applicants contended that the proposed sales will result in a positive contribution to the Alberta Border Price Adjustment Fund since the netback to Alberta border will be \$.54 Canadian per million British thermal units (MMBtu) above the current Alberta border price.

The applicants argued that ConsoliGas was being obstructive and had delayed proceedings. They asked the Board to act quickly to approve the applications.

5 VIEWS OF CONSOLIGAS

ConsoliGas did not submit any evidence or take any position on the applications in argument. ConsoliGas questioned whether the proposed sales by Poco and Tricentrol would be truly incremental. It argued that Northern Natural Gas Company (Northern Natural) currently obtains approximately 10 per cent of its supply of natural gas from Alberta sources such as Consolidated Natural Gas Limited and Pan Alberta Gas Limited. Northern Natural supplies Northern State Power Company with its full requirements of natural gas for resale and distribution in the market area in which Simplot owns and operates its food processing plant.

ConsoliGas questioned in argument whether more gas would move under the proposed removal permits due to the interruptible nature of the commitments of the buyer, sellers, and transporters. It also questioned whether the proposed gas sale would be priced competitively with competing fuels. It argued that Large Volume Contract Service (LVCS) gas and No. 6 fuel oil are the competing fuels. Since these are currently about $.75 per MMBtu higher than the proposed contract price, ConsoliGas said it believed that the price offered to Tricentrol by Simplot is too low.

6 VIEWS OF IPAC

IPAC argued that the Board's test of incrementality as stated in Decision D 85-9 was narrow. IPAC views the sale to Simplot as truly incremental and took no position regarding the issue of price competitiveness.

7 VIEWS OF TRANSCANADA

TransCanada did not take any position on the applications. However, it noted that there is Canadian gas in the system in the market area and that this should be considered by the Board in determining whether or not the proposed sale is incremental.

8 VIEWS OF THE BOARD

Having regard for existing permit commitments, Alberta's present and future needs for gas, and the established and expected future reserves of Alberta gas, the Board agrees with the applicants that the small volume of gas proposed to be removed is surplus to Alberta's requirements.

The Board is satisfied that each applicant has under its control sufficient gas to meet the volumes applied for.

The Board notes that Simplot does not presently purchase any significant volumes of gas from Northern Natural and the proposed sales would therefore result in an increase in the total sales of Alberta gas. The Board is also satisfied that the gas would be priced competitively with respect to competing fuels in the U.S. and the sale is in the public interest. The Board believes U.S. domestic gas available on the spot market represents the alternative fuel. Given the status of the study by Simplot to use coal as a fuel source and the time necessary to convert to its use, the Board does not consider coal as a viable alternative source of fuel for these applications. To ensure that reasonable net benefits would continue to accrue to Alberta as a result of the sale throughout the permit term, the Board believes that any permits issued to the applicants should be subject to the following conditions:

> The Permittee shall,
>
> (a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and
>
> (b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.
>
> The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

9 DECISION

In light of its findings and responsibilities under the Act, the Board, with the approval of the Minister

of Energy and Natural Resources, is prepared to grant gas removal permits to Tricentrol and Poco as applied for. The permits would be in the form shown in Appendix A and would be subject to the terms and conditions contained therein, as well as to conditions imposed by the Minister of Energy and Natural Resources.

DATED at Calgary, Alberta, on 4 July 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

F. J. Mink, P.Eng.
Acting Board Member

H. J. Webber, P.Eng.
Acting Board Member

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Poco Petroleums Ltd. authorizing the removal of gas from the Province

PERMIT NO. PP 85-1

WHEREAS Poco Petroleums Ltd. has applied in Application No. 850140 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Poco Petroleums Ltd. is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Poco Petroleums Ltd. (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

   (a) during the term of the permit, a total of 30 850 000 cubic metres, nor

   (b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 42 300 cubic metres and in a 12-month period such rates shall not exceed 15 400 000 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Link	Fenn-Big Valley
Hackett	Maple Glen
Provost	

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1), shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipelines of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

APPENDIX A TO PERMIT NO. PP 85-1

Department of Energy and Natural Resources

MINISTERIAL APPROVAL

Edmonton, Alberta
July 1985

Pursuant to section 10(2) of the Gas Resources Preservation Act, I, J. Zaozirny, Minister of Energy and Natural Resources, approve the granting of Permit No. PP 85-1 by the Energy Resources Conservation Board to Poco Petroleums Ltd.

____

MINISTER OF ENERGY AND NATURAL RESOURCES

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Tricentrol Oils Limited authorizing the removal of gas from the Province

PERMIT NO. TO 85-1

WHEREAS Tricentrol Oils Limited has applied in Application No. 850144 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Tricentrol Oils Limited is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Tricentrol Oils Limited (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 30 850 000 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 42 300 cubic metres and in a 12-month period such rates shall not exceed 15 400 000 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove orcause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Pouce Coupe
Watts
Bentley
Rosalind

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1), shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipelines of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

APPENDIX A TO PERMIT NO. TO 85-1

Department of Energy and Natural Resources

MINISTERIAL APPROVAL

Edmonton, Alberta
July 1985

Pursuant to section 10(2) of the Gas Resources Preservation Act, I, J. Zaozirny, Minister of Energy and Natural Resources, approve the granting of Permit No. TO 85-1 by the Energy Resources Conservation Board to Tricentrol Oils Limited.

MINISTER OF ENERGY AND NATURAL RESOURCES

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION FOR GAS REMOVAL PERMIT NORTHRIDGE PETROLEUM MARKETING, INC.

Decision D 85-29
Application 850382

1 APPLICATION

Northridge Petroleum Marketing, Inc. (Northridge) applied to the Energy Resources Conservation Board (Board), pursuant to section 2 of the Gas Resources Preservation Act (the Act), for a permit authorizing the removal of gas from Alberta. The permit would

- provide for the removal, in total, of 310.2 million cubic metres of gas,
- provide for the maximum annual removal of 155.1 million cubic metres of gas,
- provide for the maximum daily removal of 708.2 thousand cubic metres of gas,
- provide for a term of permit commencing with approval by the Minister of Energy and Natural Resources and ending on 1 November 1986, and
- name 10 fields from which gas may be obtained for removal from the province.

Northridge requested the permit for the purpose of supplying gas to Bethlehem Steel Corporation (Bethlehem) of Bethlehem, Pennsylvania, U.S.A., for use at a steel mill owned by Bethlehem in Burns Harbour, Indiana. Northridge would purchase the gas in Alberta and arrange for transportation through the NOVA, AN ALBERTA CORPORATION and Trans-Canada PipeLines Limited (TransCanada) systems to Emerson, Manitoba. Bethlehem would arrange for transportation of the gas from Emerson to Burns Harbour.

Northridge submitted that Bethlehem currently purchases 30 per cent of its 1984 average daily consumption at Burns Harbour from independent U.S. producers, and that the applied-for gas volumes would only displace these purchases; no existing Canadian export of gas would be directly displaced. Northridge also submitted that the proposed gas removal would provide a positive contribution to the Alberta Border Price Adjustment Fund, and result in direct economic benefits to Alberta.

2 NOTICE OF FILING AND SUBMISSIONS

The Board published a "Notice of Filing" respecting the application on 24 May 1985. Submissions were received from TransCanada and Canterra Energy Ltd. (Canterra), both stating an interest in the application. TransCanada referred to an earlier decision of the Board, Decision D 85-9 (ConsoliGas Management Ltd.—7 May 1985), and commented on the incrementality criteria used by the Board in that decision. TransCanada also submitted "that it is encumbent upon the applicant to show that it has made arrangements for transportation of the gas through the facilities of TransCanada".

On 20 June 1985, Northridge submitted a letter which it had received from TransCanada prior to filing the application, in which, according to Northridge, TransCanada had indicated a willingness to transport gas subject to the necessary regulatory approvals and pipeline capacity.

The Board has concluded that neither TransCanada nor Canterra would be directly and adversely affected by approval of the application.

3 ISSUES

Section 5(3) of the Act provides that the Board shall not grant a permit for removal of gas from the province unless in its opinion it is in the public interest having regard for, among other considerations,

- the present and future needs of persons in Alberta,
- the established reserves and the trends in growth and discovery of reserves of gas in Alberta, and
- the expected economic costs and benefits to Alberta of the removal of the gas from Alberta.

The Board has concluded that the only issue in the subject application is whether or not the economic costs and benefits of the proposed removal would be in the public interest of Alberta.

4 ARE THE ECONOMIC COSTS AND BENEFITS IN THE ALBERTA PUBLIC INTEREST?

4.1 Board's Views

The Board believes that the key questions to be addressed in assessing the matter of economic costs and benefits are

- Whether the proposed sale would be incremental and would result in an increase in the total sales of Alberta gas.
- Whether the gas would be priced competitively with respect to competing fuels.
- Whether the netback to the Alberta border (the market price less transmission and other costs) would be reasonable in comparison to netbacks resulting from sales to other markets, with suitable transportation arrangements having been made.

The Board is satisfied that the proposed sale of gas to Bethlehem would represent a new market for Alberta gas, and would therefore result in an increase in the total sales of Alberta gas. The Board is also satisfied that the gas being sold to Bethlehem would be priced competitively with respect to competing fuels.

The Board believes that reasonable net benefits would accrue to Alberta as a result of the sale, and in order to ensure the continuance of such reasonable net benefits to Alberta, the Board believes that any permit issued to Northridge in respect of Application 850382 should be subject to the following conditions:

The Permittee shall,

(a) before removal of gas from the province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border,

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas, and

(c) satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

5 DECISION

In light of its findings and responsibilities under the Act, the Board, with the approval of the Minister of Energy and Natural Resources, is prepared to grant a gas removal permit to Northridge as requested in the subject application. The permit would be in the form shown in Appendix A and would be subject to the terms and conditions contained therein, as well as any conditions imposed by the Minister of Energy and Natural Resources.

DATED at Calgary, Alberta, on 8 July 1985.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy
Vice Chairman

FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Northridge Petroleum Marketing Inc. authorizing the removal of gas from the Province

PERMIT NO. NM 85-2

WHEREAS Northridge Petroleum Marketing Inc. has applied in Application No. 850382 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Northridge Petroleum Marketing Inc. is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Northridge Petroleum Marketing Inc. (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a term commencing on the date hereof and ending 1 November 1986.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

   (a) during the term of the permit, a total of 310 200 000 cubic metres, nor

   (b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 708 200 cubic metres and in a 12-month period such rates shall not exceed 155 100 000 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Carbon	Duncan	Newbrook	Twining
Cranberry	Ghost Pine	Strachan	
Crimson	Kaybob	Swalwell	

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October, shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1), shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipelines of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

APPENDIX A TO PERMIT NO. NM 85-2

Department of Energy and Natural Resources

MINISTERIAL APPROVAL

Edmonton, Alberta
July 1985

Pursuant to section 10(2) of the Gas Resources Preservation Act, I, J. Zaozirny, Minister of Energy and Natural Resources, approve the granting of Permit No. NM 85-2 by the Energy Resources Conservation Board to Northridge Petroleum Marketing Inc.

MINISTER OF ENERGY AND NATURAL RESOURCES

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ALBERTA GAS CHEMICALS LTD. INDUSTRIAL DEVELOPMENT PERMIT TO MANUFACTURE AMMONIA

Decision D 85-30
Application 841207

1 INTRODUCTION

Alberta Gas Chemicals Ltd. (AGCL) applied, pursuant to section 30 of the Oil and Gas Conservation Act (Act), for an industrial development permit authorizing the annual use of 741 million cubic metres (10^6 m^3) of hydrogen as raw material and 36.6 x 10^6 m^3 of natural gas as fuel, in the production of ammonia at a new plant which would be constructed adjacent to the applicant's existing methanol facilities at Medicine Hat. The ammonia plant would produce approximately 357 thousand tonnes of product per year, when operating at capacity. A 20-year permit term was requested.

Coincident with the ammonia plant application, AGCL applied under the Act for amendment of Industrial Development Permit No. AGC 80-2, for authorization to use an additional 124 x 10^6 m^3 of gas annually to replace hydrogen as fuel in Methanol Unit III at Medicine Hat, and for authorization to use an additional 107 x 10^6 m^3 of gas annually to replace hydrogen as fuel in Methanol Units I and II. Since Methanol Units I and II are both exempt under the Act and no change to their original methanol production capacities is being requested, the latter request was deemed unnecessary by the Board. An extension of the term of Permit No. AGC 80-2 was also requested, to provide a term equal to the term of the proposed ammonia plant permit.

A public hearing of the application was held in Calgary, Alberta, on 7 and 8 May 1985, with V. Millard, N. Strom, P.Eng., and R. G. Paterson, P.Eng., sitting.

The parties who appeared at the hearing are identified in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Alberta Gas Chemicals Ltd. (AGCL) K. F. Miller	A. E. Egglestone K. H. MacRae R. Nageswaran
Canadian Fertilizers Limited (CFL) Western Co-operative Fertilizers Limited D. G. Hart, Q.C.	D. B. Smith J. H. Sultenfuss G. N. Buckley
Esso Chemical Canada (Esso) B. E. Brophy	W. J. McAdam W. R. Snyder
Cominco Ltd. F. V. Martin	
Energy Resources Conservation Board staff C.J.C. Page D. D. Fraser M. E. Mumby	

2 ISSUES

The Board considers the main issues to be

- availability of feedstock,
- efficient use of natural gas and hydrogen,
- markets for the ammonia product, and
- impacts of the proposed project on existing Alberta ammonia producers.

3 AVAILABILITY OF FEEDSTOCK

AGCL stated that natural gas would be obtained from various Alberta producers and transported through the NOVA pipeline system to Medicine Hat. Hydrogen requirements would be obtained entirely from off-gas streams of the applicant's existing three methanol plants at Medicine Hat. The hydrogen is presently used as fuel in the methanol plant reformers and would be replaced by additional natural gas. The ammonia plant would therefore depend on the reformer sections of the methanol facilities. AGCL stated that the efficiency of the ammonia plant would be reduced by operation of the methanol plants at less than their full capacities, but that production of ammonia could continue at full capacity even if no methanol were being produced.

Over the requested 20-year permit term the total volume of hydrogen required by the ammonia plant would be 14.82 billion cubic metres (10^9 m^3). On an energy equivalent basis, additional natural gas requirements for the three methanol plants would be 4.62 x 10^9 m^3. The ammonia plant would require 732 x 10^6 m^3 of natural gas during the same period for steam generation. The above volumes assume normal operation during 333 days of each year.

The Board believes that sufficient hydrogen and natural gas will be available for the proposed project but notes that gas supply arrangements have not been concluded. AGCL would therefore be required to advise the Board of satisfactory arrangements for the supply of hydrogen and natural gas, in the event that a permit is issued.

4 EFFICIENT USE OF HYDROGEN AND NATURAL GAS

AGCL proposes to purify hydrogen available from its three methanol plants, to construct an air separation unit for the production of liquid and gaseous nitrogen, and to synthesize purified hydrogen and nitrogen to produce ammonia in an energy efficient process loop. The plant would be capable of producing ammonia at an energy consumption rate of 24.6 x 10^6 joules per kilogram, which is approximately 15 per cent lower than current "state-of-the-art" methane-based ammonia plants and some 30 per cent lower than that of many older plants in operation today. AGCL stated that the main reason for the greater energy efficiency of its proposed plant over conventional methane-based plants is the elimination of the reforming section, but that energy consumption per tonne of ammonia would be higher if any of the methanol plants were shut down. Integration of the ammonia plant steam system with the steam systems of the existing methanol plants would also reduce energy consumption in the ammonia plant.

The Board is satisfied that hydrogen and natural gas would be used efficiently in the proposed ammonia plant, but notes that the efficiency of the plant is dependent to a significant degree on production rates of the applicant's methanol facilities.

5 MARKETING OF AMMONIA

5.1 Applicant's Views

AGCL provided its estimate of nitrogen demand and supply over the 1986-1995 time period for the market area consisting of Western Canada and 12 states in the northwestern portion of the U.S.* The AGCL forecast indicates a substantial increase in Canadian demand but essentially no growth in the U.S. market area. In total, the projected growth in demand for Western Canadian ammonia would be about equivalent to the production of two plants of the size proposed in this application during 1985-1990 and an additional plant during 1990 to 1995. The applicant indicated that the market analysis was derived from a project feasibility report prepared by the consulting group of Blue, Johnson and Associates. The market analysis included the states of California, Nevada, Utah, and Colorado which are considered to be new market areas outside of the traditional eight states currently served by Alberta producers.

AGCL indicated in its application that it intends to displace obsolete U.S. ammonia production within

* Washington, Oregon, Montana, Idaho, Wyoming, North and South Dakota, Minnesota, Colorado, Utah, Nevada, and California.

the U.S. marketplace. AGCL also contended that since it had identified sufficient market growth in the combined Canadian and U.S. market area to absorb the production from its proposed project, it had not attempted to identify new incremental markets. It was AGCL's position that sales from the proposed project would not result in current Alberta producers being excluded from the marketplace, and any realignment of sales involving those producers would take place within the levels of increasing demand. In response to requests by the interveners to prove incrementality of markets, AGCL contended that the interveners had indicated that they were prepared to meet new competition in the marketplace and therefore proof of incrementality was unnecessary.

5.2 Interveners' Views

CFL and Esso expressed concern that the ammonia markets, in the preferred market areas as indicated by the applicant, are currently in an excess supply to demand situation. For example CFL stated that existing plants in the U.S. and Canada could supply an additional 4 million tonnes of ammonia per year. By further example Esso submitted that it started up a new urea facility at Redwater, Alberta, in 1983 and then followed with a shut-down of this facility from June 1983 until March 1984 due to lack of demand. In 1984 it was able to operate at reasonable rates only because of offshore exports, otherwise capacity utilization would have been 70 per cent. Esso also stated that it had shut down the same urea unit in April 1985 due to lack of demand and faced further possible shut-downs in 1985. Esso stated that while it is prepared to meet competition in the marketplace, it questions whether the proposed marketing strategies of the applicant would be in the public interest.

Both CFL and Esso contended that the Canadian market would increase at a slower rate than forecast by the applicant. CFL forecast a 2 to 4 per cent annual growth and Esso forecast a 4 to 5 per cent growth, versus the applicant's view that the annual growth rate in Western Canada ammonia demand would be 9 per cent over the next 5 years. CFL and Esso agreed that there would be virtually no growth in the traditional U.S. market area. With respect to the four additional states AGCL included in its market area Esso contended that, alternate supply sources would likely have easier access to those areas than would the Alberta manufacturers.

Esso noted that AGCL stated in the application its intention to market 90 to 95 per cent of its production in the U.S. marketplace. Concern was expressed that AGCL's displacement of existing production from U.S. sources might not happen, so that AGCL production would inevitably be shifted to the Canadian marketplace which in turn could crowd out some current suppliers to that market. Additionally, Esso expressed concern that, since the AGCL proposal would be totally debt financed, the need to satisfy debt repayments would put further pressure on the applicant to place production in the Canadian marketplace if U.S. markets did not solidify.

Esso requested that additional evidence be provided by AGCL to the Board confirming the nature of its sales contracts for production going into the U.S. marketplace. CFL further requested evidence be provided that confirms the AGCL production will supply new incremental markets and that sales by current Alberta manufacturers will not be displaced.

5.3 Board's Views

On the strength of the evidence presented, the Board concludes that the Canadian market will not expand as rapidly as forecast by the applicant and it can see no reason for questioning the more-or-less unanimous view of static ammonia demand in U.S. markets. Total market growth suggests that possibly one additional plant of the size being applied for could be accommodated. However, with respect to the U.S. market, it is not just the change in demand that has relevance but who supplies that demand, particularly in that area where Canadian producers can compete with domestic manufacturers. It appears to the Board that the higher efficiency of AGCL's proposed plant, together with its favourable distance to U.S. market points, could permit AGCL to penetrate additional market areas thereby increasing total Canadian sales.

In regard to the interveners' concerns that AGCL would displace current sales contracts, the Board believes that any such displacements would in turn be offset by alternate market sales opportunities in the overall market region.

6 PROJECT IMPACT

6.1 Applicant's Views

AGCL stated that the proposed project would be constructed over a 24-month period, with 307 man-years of construction labour employed. The capital cost of the project would be $102.7 million, with 42 per cent to be spent in Alberta. Annual operating expenditures are estimated to be $36.6 million, annual

revenue is expected to be $68.9 million, and it is estimated that 50 permanent full-time jobs would be created by the project. AGCL indicated that over the 20-year life of the project, provincial tax revenue generated would be $51 million and federal tax generated would be $182 million. The total direct and indirect impact of this project over the 20-year life is estimated to be $2.2 billion.

AGCL contended that in the event its forecasted market growth is incorrect, it believes the positive impact of the project would still outweigh the negatives. AGCL indicated that no evidence was submitted on the degree of negative impact that either Esso or CFL believed would result from this project. AGCL believed that the factors concerning the highly efficient natural gas utilization in the manufacture of ammonia and the high degree of Alberta ownership in the project provide for a net positive impact to the province, even under static market conditions.

6.2 Interveners' Views

CFL submitted that the installation of increased production capacity at this time would create downward pressure on prices, and could lead to reduction of existing sales from the province. It contended that permitting the AGCL project to proceed, in light of oversupplied U.S. markets, would lead directly to a sharp drop in sales by CFL, unemployment in the CFL work force, and a resultant loss of Alberta revenues. CFL submitted that with its higher gas costs, it would be disproportionately affected and that there would be no net benefit to Alberta.

Esso's primary concern was the value of the project to the Alberta public interest and the impact on existing Alberta nitrogen fertilizer producers. Esso's main interest was to ensure an orderly entry of new Alberta production capacity into the marketplace without displacement of current production.

6.3 Board's Views

The Board accepts the applicant's estimate that the proposed project would provide direct and indirect benefits to the province of some $2 billion over its 20-year life.

The concerns expressed by the interveners respecting the impact the plant would have on existing ammonia manufacturing operations have been carefully considered. The Board recognizes the many uncertainties in projecting future ammonia markets. However, as indicated in Section 5.3, it believes that there will be growth in the Canadian market and that the applicant, with its greater processing efficiency and favourable location, should be able to penetrate new market areas in the U.S. While the proposed project would increase the provincial ammonia productive capacity by 14 per cent, the Board expects that the enlarged market area along with market growth will be able to absorb the additional production. It recognizes, however, that there could be some marketing problems during the initial years.

Having regard for all of these considerations, including the high level of Alberta public ownership in the project, the Board concludes that the proposed project would provide net positive benefits to the province.

7 DECISION

Having regard for its responsibilities under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to grant the applied-for industrial development permit to Alberta Gas Chemicals Ltd. The permit would be in the form shown in the attachment, and would be subject to the terms and conditions contained therein and to any terms and conditions imposed by the Lieutenant Governor in Council.

DATED in Calgary, Alberta, on 8 August 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

N. Strom
Board Member

Mr. R. G. Paterson, Acting Board Member, concurs with the contents and with the issuing of this report.

APPENDIX
FORM OF PERMIT*

IN THE MATTER of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Alberta Gas Chemicals Ltd. authorizing the use within Alberta of hydrogen and natural gas produced in Alberta for the production of ammonia

INDUSTRIAL DEVELOPMENT PERMIT NO. AGC 85-1

WHEREAS Alberta Gas Chemicals Ltd. has applied in Application No. 841207 to the Energy Resources Conservation Board for an industrial development permit, pursuant to section 30 of the Oil and Gas Conservation Act, authorizing the use of hydrogen and natural gas produced in Alberta for the production of ammonia in Alberta; and

WHEREAS the Board, upon inquiry into the application, is of the opinion that the granting of this industrial development permit for the use of hydrogen as raw material and natural gas as fuel for production of ammonia is in the public interest, having regard to, among other considerations, the efficient use without waste of energy resources and the present and future availability of hydrogen and natural gas in Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council numbered and dated 1985, has authorized the granting of the permit.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Alberta Gas Chemicals Ltd. (hereinafter called "the Permittee") authorizing the use of hydrogen as raw material and natural gas as fuel for production of ammonia, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. This permit is for the use in Alberta by the Permittee of hydrogen as raw material and natural gas as fuel for the production of approximately 357 000 tonnes per year of ammonia, generally as described in the application to the Board dated 22 November 1984.

2. The plant facilities at which ammonia will be produced shall be located in Section 14, Township 13, Range 6, West of the 4th Meridian.

3. Subject to compliance by the Permittee with the terms and conditions hereof, this permit shall be for a term commencing on the date hereof and ending on 31 August 2007.

4. The quantities of hydrogen and natural gas that may be used in the industrial operation referred to herein shall not exceed 741 000 000 cubic metres per calendar year and 36 626 000 cubic metres per calendar year, respectively.

5. The quantities of gas for the purpose of this permit shall be on the basis of a gas free of water vapour and having a higher heating value of 37.4 megajoules per cubic metre.

6. All hydrogen and natural gas used in producing ammonia pursuant to this permit shall be measured by or on behalf of the Permittee in a manner satisfactory to the Board, and the volumes of hydrogen used as raw material and

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

natural gas used as fuel and of ammonia produced shall be separately reported to the Board in a manner satisfactory to the Board.

7. The Permittee shall obtain the approval of the Board of any major changes in design of the plant facilities.

8. (1) The Permittee shall satisfy the Board prior to 30 November 1985, or such other date as the Board upon application by the Permittee may stipulate, that arrangements for the financing of its proposed project have been completed.

(2) The Permittee shall satisfy the Board prior to 31 December 1985, or such other date as the Board upon application by the Permittee may stipulate, that construction of its proposed facilities has commenced.

(3) The Permittee shall satisfy the Board prior to 30 June 1986, or such other date as the Board upon application by the Permittee may stipulate, that arrangements for the supply of the necessary hydrogen and natural gas volumes have been completed.

9. During construction of the industrial operation referred to herein, the Permittee shall report to the Board semi-annually, in a manner satisfactory to the Board, with respect to the progress of construction.

10. The Permittee shall operate the facilities in a manner that results in

(a) the maximum practically obtainable efficiency in the use of hydrogen and natural gas for the manufacture of ammonia, and

(b) the maximum practical conservation of hydrogen and natural gas.

11. The Permittee shall not

(a) assign this permit, or

(b) release from his control the operation of the plant,

without the consent in writing of the Board, which consent may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

12. (1) Attached hereto as Appendix A, and made part of this permit, is the Order of the Lieutenant Governor in Council authorizing the granting of this permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the Order of the Lieutenant Governor in Council set out in Appendix A.

13. Where it appears to the Board or the Lieutenant Governor in Council that the Permittee has contravened or failed to comply with any terms or conditions contained in this permit or any relevant statutes or regulations of Alberta

(a) the Board shall review the permit and with the approval of the Lieutenant Governor in Council may cancel the said permit or take such other remedial measures as considered suitable by the Board and the Lieutenant Governor in Council in the circumstances, or

(b) the Lieutenant Governor in Council may amend, vary, add to or replace any terms or conditions contained in this permit.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this day of 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

IN THE MATTER of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Alberta Gas Chemicals Ltd. authorizing the use within Alberta of gas produced in Alberta for the production of methanol

AMENDMENT NO. 1 OF INDUSTRIAL DEVELOPMENT PERMIT NO. AGC 80-2

The Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, having regard to the application dated 22 November 1984, of the Permittee and having regard to its responsibility under the Act, and the Lieutenant Governor in Council, having given his approval by Order in Council dated 1985, and numbered O.C. , hereby orders as follows:

1. Industrial Development Permit No. AGC 80-2 is amended.
2. Clause 3 is amended by striking out the date therein, and by substituting the date 31 August 2007.
3. Clause 4 is struck out and the following is substituted:

   4. The quantity of gas that may be used in the facilities referred to herein in the production of methanol shall not exceed

      (a) 436 015 000 cubic metres per calendar year as raw material nor 164 092 000 cubic metres per calendar year as fuel, or

      (b) 12 003 000 000 cubic metres during the term of the permit referred to in clause 3.

4. Appendix A is struck out and Appendix A hereto attached is substituted.

MADE at the City of Calgary, in the Province of Alberta, this day of , 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard
Chairman

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

WESTCOAST PETROLEUM LTD. GAS PROCESSING PLANT PIPELINE PERMIT 21538

Decision D 85-31
Applications 850337 and 850580

1 APPLICATION AND HEARING

Westcoast Petroleum Ltd. (Westcoast) applied, pursuant to section 26 of the Oil and Gas Conservation Act and Regulations, for approval of a scheme for the processing of sweet solution gas gathered from a central battery serving the Crystal Viking 'A' Unit in the Crystal Field. The proposed plant site would be constructed at the existing central battery site located in legal subdivision 9 of section 6, township 46, range 3, west of the 5th meridian (9-6 site). The plant would be designed to process a maximum of 211 thousand cubic metres per day (10^3 m^3/d) of solution gas from which 192 x 10^3 m^3/d of sales gas, 57 m^3 of liquefied petroleum gases (LPG mix), and 25 m^3 of pentanes plus would be recovered.

Westcoast further requested that Pipeline Permit 21538 issued by the Board on 11 March 1985 be reaffirmed. Westcoast had agreed to cease construction of the pipeline pending resolution of an objection by Bumper Development Corporation Ltd.

The applications were considered at a public hearing on 3 and 4 July 1985 in Calgary, Alberta, with V. E. Bohme, P.Eng., C. J. Goodman, P.Eng., and J. A. Bray, P.Eng., sitting.

Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Westcoast Petroleum Ltd. (Westcoast) K. F. Miller	A. J. Kostyniuk, P.Eng. R. J. Giroux, P.Eng. W. Snyder, P.Eng. W. R. Hartt, P.Eng. (of Duckworth, Price, Henderson & Associates Ltd.)
Bumper Development Corporation Ltd. (Bumper) G. Watkins	W. A. Trickett, P.Eng. D. B. Domier, P.Eng. K. J. Edinga, P.Eng. C.D.W. Johnson, P.Eng. (of Gemini Engineering Ltd.)
Northwestern Utilities Limited (NUL) C. K. Sheard	
Energy Resources Conservation Board staff C.J.C. Page E. P. Moeller, C.E.T. L. S. Fillion, C.E.T. N. C. Harris, P.Eng. R. O. Komesch T. Walden	

Chieftain Development Corporation Co. Ltd. submitted an intervention but did not appear at the hearing.

NUL stated that it was appearing at the hearing for the purpose of cross-examination regarding only the pipeline application.

2 BACKGROUND

On 19 March 1985 the Board considered a request by Bumper, which operates a gas plant in the Crystal Field, to suspend ERCB Pipeline Permit 21538 issued to Westcoast, since the new line was intended to serve a new Westcoast plant to be located 1.6 kilometres (km) from the Bumper plant. Subsequently, Westcoast committed to the following:

- immediately file an application for the proposed gas plant,
- cease construction of the pipeline under Permit 21538, and
- have the pipeline matter considered at the hearing for the proposed gas plant.

3 INTERVENTIONS

Bumper was the principal intervener and its submission dealt mainly with the need for, and economics of, two plants in the Crystal Field and its efforts to reach an agreement regarding sharing its plant and pipeline with Westcoast.

4 ISSUES

The Board considers the issues regarding the applications to be:

- early conservation of gas,
- need for two sales gas pipelines,
- need for two plants,
- economics of one or two plants and pipelines,
- environmental impacts, and
- public interest.

5 EARLY CONSERVATION OF GAS

Westcoast stated that in August 1983 it attended a meeting with area producers with respect to unitization of the Crystal Field and plans for waterflooding the Crystal Viking A Pool. The applicant said that it received waterflood approval in June 1984 and completed construction of the central 9-6 battery in December of that year. Westcoast stated that it proceeded to obtain a sales gas contract with TransCanada PipeLines Limited (TransCanada) for its solution gas and applied for a permit to construct a sales gas pipeline from the 9-6 battery site to a NOVA, AN ALBERTA CORPORATION (NOVA) metering station located at Legal Subdivision 4-28-43-4 W5M some 22 km to the south.

The applicant stated that it filed an application for construction of its proposed gas plant following the meeting with the Board and Bumper held 19 March 1985, at which Bumper objected to construction of the pipeline.

Westcoast said that it had proceeded with a scheme for the conservation of gas in an orderly fashion once the field had been delineated and waterflooding commenced. Westcoast said that it did not accept an offer from Bumper to participate in Bumper's scheme to build a gas plant in 1983 because Westcoast considered the Bumper scheme to be premature. Additionally, Westcoast stated that its proposed plant would be at the best location for the unit's operations. Further, since Westcoast is the largest producer in the Crystal Field, it contended that it should operate any gas processing facility which processed its gas.

Westcoast said that it could conserve gas immediately after completing construction of its sales gas pipeline because it had negotiated a contract with NOVA to take unprocessed gas for an interim period while its gas plant is being built. Westcoast estimated that it would take about 1 month to complete the pipeline.

Bumper submitted that it built a gas processing plant in 1983 at Lsd 16-36-45-4 W5M in order to effect early conservation of Crystal Field solution gas. Bumper stated that at that time, it contacted all operators in the Crystal Viking A Pool, including Westcoast, and offered processing capacity and participation in its plant. However, it also said that to date, only one operator had contracted for processing services in the plant. Bumper also stated that none of the operators had negotiated equity participation in the plant.

Bumper said that it currently has excess plant and pipeline capacity and could process most of the Westcoast gas within about 30 days. It also stated that it could expand its plant to process all of the Crystal Field gas. Bumper contended that there is no need for a second plant in the area and that Westcoast should participate in the Bumper plant to effect the earliest

possible means of conserving gas flared from Westcoast's 6-9 battery. Bumper said that a pipeline could be built to tie in the Westcoast 6-9 site to the Bumper plant and hence avoid proliferation of plants and pipelines in the area.

Bumper offered to process Westcoast's gas for an interim period while the Westcoast plant is being built, should the plant be approved.

The Board notes that Westcoast and Bumper both believe that gas could be conserved in about a month's time either by processing at Bumper's plant or by completing the Westcoast sales gas pipeline. The Board believes that either proposal would be satisfactory provided that gas is conserved at the earliest possible date.

6 NEED FOR TWO SALES GAS PIPELINES

Westcoast said that it required its own sales gas pipeline and its contract is with TransCanada. Westcoast stated that it had rejected the proposal to use the Bumper pipeline because it would require gas to be transported through the NUL system and thus would be subject to an additional tariff. Therefore, utilizing the Bumper pipeline would be less economic for Westcoast, when compared to its proposed pipeline.

Bumper opposed Westcoast's plans to build a second sales gas pipeline because it would needlessly duplicate existing facilities in the area. Bumper said that its pipeline could handle all the gas produced from the Crystal Field.

The Board agrees that Bumper's pipeline likely would be able to accommodate all of the Crystal Field gas; however, it recognizes that the nature of the sales gas contracts and pipeline transportation costs for Bumper and Westcoast are inherently different. Thus, the Board believes that it is preferable from Westcoast's point of view to be able to deliver gas to TransCanada through its own pipeline. Therefore, the Board concludes that there may be justification for Westcoast to build its own pipeline.

7 NEED FOR TWO PLANTS

Westcoast said that it requires gas processing facilities large enough to process up to 211 x 10^3 m^3/d of gas gathered from its wells and those of other operators in the Crystal Field. Westcoast said that it considered participating in the nearby Bumper plant but rejected it because the Bumper plant would have to be expanded and Westcoast would not be operator of the facility even though the unit would be the major participant. Bumper said that it offered Westcoast capacity and equity participation in its plant and was prepared to expand its facility to accommodate all the Crystal Field solution gas. Bumper said that a new Westcoast plant was not necessary and constituted a duplication of facilities.

The Board acknowledges that Bumper's plant could be expanded but recognizes Westcoast's view that the unit is the largest producer of gas in the field and wants to operate its own facility. The Board also notes that Westcoast has obtained consent from area residents with respect to construction of its own facility. The Board sees no reason to intervene in normal business transactions unless there are issues related to such matters as conservation or environment protection. In this case the Board notes that Westcoast's proposed scheme would be technically sound, would result in the conservation of solution gas, and is environmentally acceptable.

8 ECONOMICS OF ONE OR TWO PLANTS OR PIPELINES

Westcoast said that it was more economic for it to build its own facilities than to participate in an expanded Bumper plant. Bumper said that it was more economic for it and Westcoast (the unit) to participate in an expanded Bumper plant.

The evidence supplied by Westcoast and Bumper indicates to the Board that the capital and operating costs of either expanding the Bumper plant or building a new Westcoast plant and pipeline were not so different that it should interfere with normal business decisions.

9 ENVIRONMENTAL IMPACTS

Environmental impact was not an issue brought up by Westcoast or Bumper. The Board recognizes that approval of additional processing facilities and pipelines in the area will create land disturbance and proliferation of facilities; however, the Board recognizes that the impacts in this case are minimal and landowner consent has been obtained. The Board believes that the now centralized flaring of the gas can be considered an adverse environmental impact and that the gas should be processed and conserved as soon as possible.

10 PUBLIC INTEREST

Westcoast and Bumper agreed that the gas should be conserved quickly and both referred to written

comments from area residents who stated that they wanted the flaring terminated. Westcoast said that it would conserve gas while its plant is being built. Bumper offered to process all of the Westcoast gas on a permanent basis or alternatively on an interim basis while the Westcoast plant is being built.

The Board is concerned that the conservation of Westcoast's solution gas has been delayed during development of the field, so that there is now a significant volume of gas being flared, exacerbated by the fact that the unit has for some time had the benefit of increased waterflood allowables.

The Board agrees that it is in the public interest to conserve the gas as soon as possible so as to provide the benefit to the public treasury from processing and sale of the gas.

11 DECISION

Having considered all of the evidence of the applicant and the interveners, the Energy Resources Conservation Board is prepared to approve Westcoast Petroleum Ltd.'s plant application and reaffirm Pipeline Permit 21538. Approval is given on the understanding that Westcoast will effect the earliest possible conservation of the flared gas at the 9-6 central battery. Failure to do so would result in the Board calling a hearing to determine the need for an order requiring gas conservation.

DATED at Calgary, Alberta, on 24 July 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman, P.Eng.
Board Member

J. A. Bray, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ALBERTA POWER LIMITED
144-kV TRANSMISSION LINE
CLAIRMONT LAKE–POPLAR HILL

Decision D 85-32
Application 850228

1 THE APPLICATION

Alberta Power Limited (Alberta Power) applied, pursuant to sections 12, 14, 16, and 17 of the Hydro and Electric Energy Act (the Act), for approval to construct and operate a 144-kV transmission line and substation northwest of Grande Prairie. The 44-kilometre (km) transmission line would be constructed from Alberta Power's existing Clairmont Lake substation, 9 km northeast of Grande Prairie, to the proposed 144/25-kV Poplar Hill substation in the northwest quarter of Section 19, Township 73, Range 8, West of the 6th Meridian (NW 19-73-8 W6M). The proposed facilities are shown on the attached Figure 1.

The application was considered at a public hearing on 4 June 1985 in Calgary, Alberta, with C. J. Goodman, P.Eng., L. A. Bellows, P.Eng., and T. F. Homeniuk, P.Eng., sitting. The hearing was to be held in Grande Prairie but was moved to Calgary by mutual agreement of the registered participants and the Board. Participants at the hearing are shown on the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Alberta Power Limited (Alberta Power) K. Miller B. O'Farrell	A. Morin, P.Eng. M. S. Allen
Bear Lake Farmers' Rights Group (the Group)* J. D. Carter	
T. Lock* J. D. Carter	
Her Majesty the Queen in Right of Alberta (the Crown)** R. Grover	
Energy Resources Conservation Board staff A. Gervais J. W. Berg, P.Eng. B. E. Olliver	

* The Group and Mr. Lock are referred to collectively in this report as "the interveners".

** The Crown registered for cross-examination purposes only, but did not participate at the hearing.

2 PRELIMINARY MATTERS

Counsel for the applicant requested a ruling that the Group was not a proper intervener with standing at the hearing. He argued that counsel for the Group had simply submitted that he represented the Group which was opposed to a portion of the applied-for transmission line route and was concerned about transmission line structures located on road allowances and overhanging onto private property. Individual members of the Group who might be directly and adversely affected by the proposed transmission line had not been identified, nor had any evidence been submitted to suggest that there would be any impacts or what they might be. He contended that this placed the applicant in the unfair position of having to respond to concerns that had not been specifically identified.

Counsel for the Group filed a Group membership list and stated that he not only represented the Group but also Mr. T. Lock, who owns land adjacent to the portion of the transmission line proposed to be located along a blind line. He also identified his father, Mr. J. Carter, as a member of the Group who owns land adjacent to a road allowance on which the transmission line is proposed to be located. Both of these landowners would have structures overhanging their properties if the proposed transmission line were approved. He noted that information describing the proposed transmission line, its route, and impacts had been submitted as part of the application and that he did not propose to file any other evidence. He intended only to ask questions of the applicant and give final argument. He contended that this would not place the applicant in an unfair position and that his clients, the Group and Mr. Lock, would be affected by any decision of the Board with respect to the proposed transmission line and, therefore, had a right to participate in the hearing.

The Board ruled that the Group and Mr. Lock had standing at the hearing and that their counsel could cross-examine the applicant's witnesses and give final argument.

3 BACKGROUND

The transmission system in the Grande Prairie area is shown schematically on the attached Figure 2. The Wembley area northwest of Grande Prairie is served from Hythe East substation which is supplied by 72-kV transmission line 6L30 from Mercer Hill substation. Normal load growth in the area is expected to exceed the firm capacity of the 72-kV system by 1986. Also, Dome Petroleum Limited (Dome) has approval and is currently constructing the Wembley Gas Plant located in the SW 19-73-8 W6M. The maximum power requirement to be added by the gas plant is expected to be approximately 21 megawatts (MW).

4 ISSUES

The Board believes the issues in this application are:

(a) the need for the proposed facilities, and

(b) the route of the proposed transmission line and location of the substation.

5 NEED FOR THE PROPOSED FACILITIES

Alberta Power proposed to construct a new 144-kV transmission line (7L22) and substation (Poplar Hill 790S) in the Wembley area to meet the energy needs of the area and of the new Dome natural gas liquids extraction plant (see Figures 1 and 2). In 1986, the plant and associated field-compression peak load is estimated to be 21 MW. The total gas plant and surrounding area load is predicted to be 35 MW in 1986. The present supply point for this area is the Hythe East substation 726S; however, this substation is on a single-line feed from 72-kV line 6L30, which has a normal capacity of 13 MW. Therefore, the new line and substation are required to make up a minimum of an additional 22 MW in 1986.

Alberta Power stated that, after the new line and substation are in place, 4 MW of the Hythe East substation load would be transferred to the Poplar Hill substation, thus reducing the demand on Hythe East substation and making the actual load on Poplar Hill about 25 MW in 1986.

Alberta Power stated that, by 1987, an outage to 144-kV line 7L39, between Crystal Lake 722S and Clairmont Lake 811S, would result in unacceptably low voltages at the Wapiti (823S) and Elmworth (731S) substations. These substations are presently supplied by single-feed 144-kV line 7L03 out of Flyingshot Lake substation 749S. Alberta Power's transmission plans for the area would probably extend the proposed transmission line 7L22 from the Poplar Hill substation to the Goodfare substation to provide a second supply to the Elmworth and Wapiti areas.

The Board is satisfied that the presently proposed facilities are required to serve the Wembley Gas Plant and to meet normal load growth in the area. It notes that these facilities are a part of the long-term system planned for the area. However, future facilities would be considered when specific applications are filed.

6 ROUTE OF THE TRANSMISSION LINE AND LOCATION OF THE SUBSTATION

Alberta Power investigated four potential routes for the proposed transmission line and discussed these in its application. Constraint factors employed in its route selection process included: the number of affected farm residences and their proximity to the proposed transmission line, impact of the transmission line on agricultural operations, conflict with existing linear facilities such as Alberta Government Telephones (AGT) facilities and power lines, environmental and wildlife concerns, overall length, and cost of construction and maintenance of the line. After comparing the impacts associated with each route, the applicant concluded that the applied-for route was the most acceptable and rejected the other routes investigated as being less acceptable or unacceptable.

In response to a query by the interveners concerning the possibility of double-circuiting the proposed line with the existing 72-kV line 6L30 that runs between the Mercer Hill and Hythe East substations, the applicant stated that the high cost and technical constraints associated with overbuilding the proposed line with the existing line made this route unacceptable. Alberta Power stated that 72-kV line 6L30 is the only supply to Hythe East substation which serves 10 MW of load in the area. Therefore, it could not be taken out of service to allow construction of the proposed line. Alberta Power stated that temporarily moving 72-kV line 6L30 and keeping it energized while it was being moved to allow construction of the new line would be technically impractical and cost prohibitive. Constructing the new line on the opposite side of the road allowance on which line 6L30 is located (referred to locally as the Emerson Trail) could give the impression of travelling through a tunnel and would, in Alberta Power's view, be unacceptable. Conflict with AGT facilities on the south side of Emerson Trail would also occur.

Alberta Power explained that it would be possible to remove the existing 144-kV line 7L68 north of Clairmont Lake substation and replace it as part of the double-circuit line proposed for this portion of the new line because Rycroft substation 730S, which is served by line 7L68, is also served by an alternative supply.

Alberta Power proposed to construct double-circuit structures immediately north of Poplar Hill substation to accommodate a possible future circuit to either the Goodfare substation or the Ksituan River substation. It stated that it would be prudent to do this at this time to avoid construction problems associated with a second line at a future date.

Alberta Power stated that its originally-proposed route in the vicinity of Henderson Lake raised concerns with the Fish and Wildlife Division of Alberta Energy and Natural Resources. The lake is an established nesting area for Trumpeter swans and the concerns related to the potential for collision of flying swans with the transmission line. Therefore, Alberta Power proposed to route the line a somewhat greater distance from the lake and plant trees to provide a barrier between the line and the lake. Agreement from two landowners affected by this route modification had been obtained.

Alberta Power stated that it has not yet acquired any easements for the line, but would initiate negotiations with landowners upon receipt of approval to construct the line. It stated that it had acquired an easement for the Poplar Hill substation site.

In response to questioning by the interveners, Alberta Power stated that it designated some of the required rights of way (ROW) as primary and some as secondary. It defined primary ROW as that necessary to construct, operate, and maintain the line. Secondary ROW is required for purposes of removing trees that are off the primary ROW but which might fall into the line. Alberta Power stated that it differentiated between the two types of ROW because it understands that the Board would not approve ROW for purposes of removing such danger trees. However, if its understanding is incorrect, Alberta Power requested that the secondary ROW be approved. It contended that it had sufficiently defined the secondary ROW, but would provide any further information the Board required.

The interveners questioned Alberta Power as to the reason for designating different ROW as primary and secondary. They argued that both types would be required to construct, maintain, and safely operate the line and that there should be no difference in their designation.

The interveners also questioned Alberta Power as to why the proposed line could not be constructed along Emerson Trail, the route of the existing 72-kV line between Mercer Hill and Hythe East substations. In their closing argument, they contended that the cost of overbuilding with the existing line would be a small price to pay to avoid a proliferation of lines in the general area. They also argued that using the existing route would avoid landowners along the new proposed route being affected by structures and conductors overhanging their properties. Even though the centre line of the proposed 144-kV line might be on a road allowance, part of the line would hang over adjacent

property and thereby affect the rights of that property owner. They contended that the Board in its decision should, therefore, prescribe ROW to accommodate any such overhang.

The Board has reviewed the process used by Alberta Power in this application for selecting and evaluating potential transmission line routes. It accepts the various constraints and potential impacts used by the applicant to evaluate possible alternative routes, and notes that evidence opposing the proposed route was not presented.

The Board considered the suggestion of double-circuiting a portion of the proposed transmission line with the existing 72-kV line along the Emerson Trail. It is the Board's view that the existing 72-kV line supplying Hythe East substation should not be taken out of service, thereby cutting off service to a large number of customers, to allow construction of the new line. Disruption of service to such a large area over a period of several days is not acceptable. Even if it were possible, the result would be two transmission circuits and a distribution circuit on the same set of structures. The Board seriously questions whether placing three voltage levels and three alternative supply sources to the area on one set of poles would provide a reliable and safe supply of service to the area. Furthermore, maintenance of a line consisting of three circuits would be difficult and hazardous. In this case, the Board does not view this as a viable alternative.

The Board has considered the applicant's stated intention to reconstruct the existing line north of Clairmont substation as part of a double-circuit line with the proposed line. Reconstruction of the existing line would not require disruption of service. The two 144-kV transmission circuits would be constructed on opposite sides of the structures so that access to either circuit would be possible for maintenance. The Board notes that a portion of this segment of line would include a rural electric distribution line as a third circuit. However, because the length of line having three circuits would be relatively short and there would be only two voltage levels, the Board finds this arrangement satisfactory.

The Board notes Alberta Power's intention to install double-circuit structures immediately north of Poplar Hill substation. The Board accepts that it would be prudent to make provision for a future circuit on this portion of the line, but cautions that this should not be construed as approval of any future transmission line.

The Board notes that the proposed line would be located to minimize the potential hazard to Trumpeter swans in the area of Henderson Lake, and that the affected adjacent landowners are in agreement with the route. It further notes that very few of the affected landowners along the entire route have objected to it, and that an easement has been obtained for the Poplar Hill substation. The Board finds the proposed transmission line route between Clairmont Lake substation and the proposed Poplar Hill substation acceptable and to be preferred over the alternatives discussed. It also finds the proposed Poplar Hill substation location, adjacent to the Wembley Gas Plant, appropriate.

The Board has considered the need for the primary and secondary ROW identified by the applicant. Alberta Power has designated the ROW that is needed to construct, operate, and maintain the proposed transmission line as primary ROW. It has clearly defined where the so-called primary ROW is required and has quantified it in terms of width. The Board concurs.

Alberta Power has also identified areas where it would be necessary to gain access to remove danger trees. It designated these areas as secondary ROW but did not define or quantify them in terms of width nor describe the extent of tree removal that would be necessary. The Board recognizes the need to remove so-called danger trees but, because the extent of tree removal that would be required was not provided and this ROW width was not defined, it does not have sufficient information to prescribe it. If the proposed transmission line were approved, the Board expects that agreements to allow removal of danger trees would be negotiated with the landowners. Failing such agreement, Alberta Power could apply to the Board, with sufficient supporting information, to have the necessary ROW prescribed. All affected parties would be provided an opportunity to express their views respecting any such application.

The Board notes the interveners' argument that there should not be a difference in designation between the two types of ROW, as defined by Alberta Power. The Board agrees. When the need for an ROW to construct, operate, and maintain a transmission line, including removal of danger trees, has been identified, defined, and quantified, the Board would normally prescribe one ROW pursuant to section 18(2)(e) of the Act. The Board recognizes that negotiated agreements with landowners to allow removal of danger trees without the placing of permanent encumbrances on land may be desirable. In this regard, the Board notes that any ROW it might prescribe would not preclude Alberta Power and a landowner from negotiating such an agreement.

The Board has considered the interveners' argument that ROW should be acquired by the applicant to accommodate a transmission line hanging over adjacent property. The Board considers that the need for ROW should be determined on the basis of that area required to construct, maintain, and safely operate the transmission line now and in the future. In this case, the Board is satisfied on the evidence it has received that the so-called primary and secondary ROW described by Alberta Power would be sufficient to meet these criteria. Accordingly, the Board has prescribed ROW as discussed in the preceding paragraphs.

7 DECISION

The Energy Resources Conservation Board is prepared to approve the application. The transmission line rights of way shall be in accordance with the primary right of way designation described in the application. The requested permits and licences will be issued upon receipt of approvals of the Minister of Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 11 July 1985.

ENERGY RESOURCES CONSERVATION BOARD

C. J. Goodman, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Board Member

T. F. Homeniuk, P.Eng.
Acting Board Member

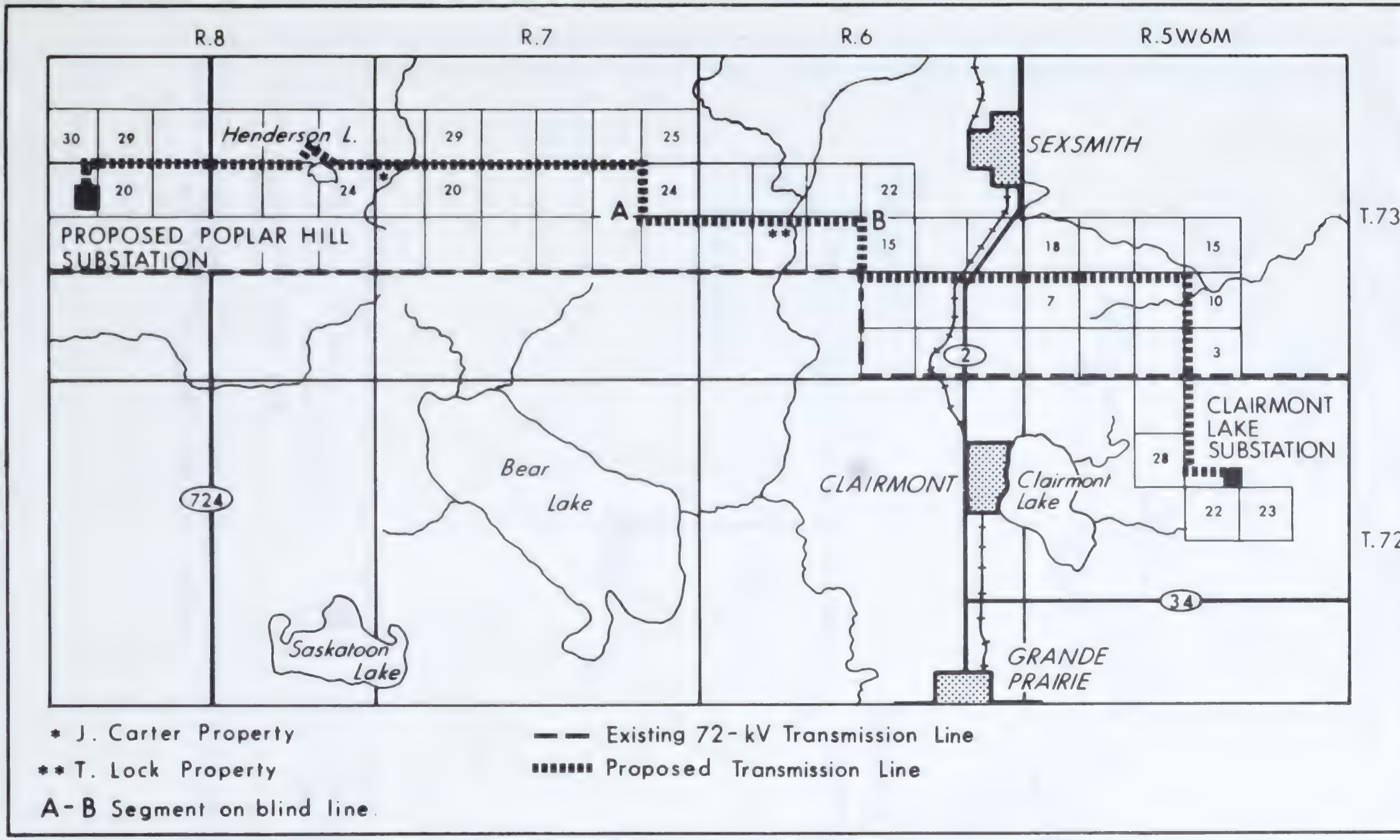


FIGURE 1 PROPOSED 144-kV TRANSMISSION LINE CLAIRMONT LAKE-POPLAR HILL AREA.

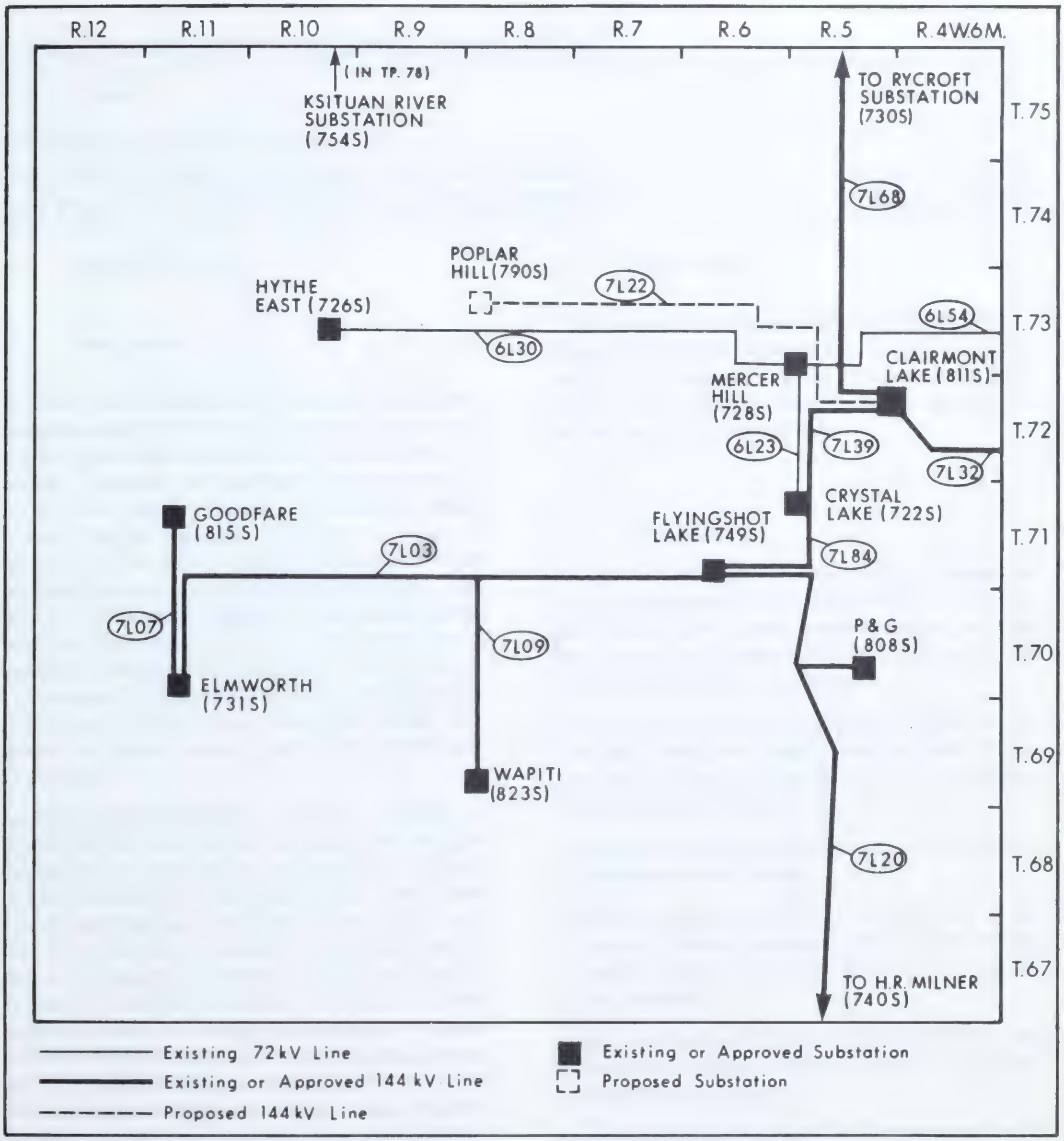


FIGURE 2 SCHEMATIC OF EXISTING ELECTRIC TRANSMISSION SYSTEM IN THE GRANDE PRAIRIE AREA

ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ANDERSON EXPLORATION LTD. APPROVAL TO MODIFY EXISTING DUNVEGAN GAS PLANT TO RECOVER ETHANE-PLUS LIQUID

Decision D 85-33
Application 850205

1 INTRODUCTION

1.1 Background

Anderson Exploration Ltd. (Anderson) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct deep-cut facilities at its existing Dunvegan gas processing plant (located in the northeast quarter of section 3, township 81, range 4, west of the 6th meridian) to remove a mixture of ethane and heavier hydrocarbons (ethane-plus) from the sales gas stream leaving the existing plant. The maximum raw gas throughput of the existing plant would not be increased above the currently approved rate of 6762 thousand cubic metres per day ($10^3\ m^3/d$). The proposed facility would recover up to 1175 cubic metres per day (m^3/d) of ethane-plus liquid. This reflects an ethane recovery level of approximately 85 per cent.

Anderson's application was opposed by a number of companies that participate in the Alberta petrochemical industry by extracting ethane, upgrading it to ethylene, or manufacturing ethylene derivatives. These interveners were opposed to the application on the basis that the extraction of ethane at field plants would reduce the amount of ethane available as a petrochemical feedstock, increase the cost of ethane extraction from the existing straddle plant system, and result in the needless duplication of existing ethane recovery facilities. They contended that uncertainty concerning the supply and cost of ethane available for petrochemical use would seriously erode investor confidence and would ultimately limit the growth of the Alberta petrochemical industry and possibly result in its demise.

In addition to the above noted interventions, the Board received submissions from 16 companies which supported Anderson's application. In general, this group represented working interest owners in the proposed project with the exception of Esso Resources Canada Limited (Esso) which had committed to purchase all of the ethane-plus produced at the plant over a 20-year period.

1.2 The Hearing

The application was considered at a public hearing in Calgary, Alberta, on 30 April, 1, 2, 3, and 8 May 1985, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and F. J. Mink, P.Eng., sitting. Those who appeared at the hearing are shown in Table 1.

2 THE ISSUES

The issues to be considered in deciding whether the proposed facilities would constitute efficient, economic, and orderly development remain unchanged from other recent applications to extract ethane in the field. These issues are as follows:

- the degree to which the proposed facilities would recover ethane and other natural gas liquids incremental to those volumes that would be recovered without the facilities;
- the present and future markets for the ethane and other natural gas liquids;
- the cost of the products to be recovered at the proposed facilities compared to the cost of recovering similar volumes of the same products elsewhere in the province;
- the potential impact of the proposed facilities on the existing straddle plant system and on the Alberta petrochemical industry;
- the impact of the proposed facilities on the potential for enhanced recovery of oil;
- the economic benefits to Alberta, including the public treasury, resulting from the incremental recovery of ethane and other natural gas liquids;
- the proprietary rights of gas producers;
- the degree of upgrading of resources within Alberta; and
- the conservation and environmental aspects of the proposed facilities.

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Anderson Exploration Ltd. (Anderson) B. K. O'Ferrall	R. A. Serin, P.Eng. G. A. Engbloom, P.Eng. (of Confer Consulting Ltd.) R. E. Heigold, P.Eng. (of Delta Projects Limited)
Alberta Natural Gas Company Ltd. (ANG) M. A. Putnam, Q.C.	D. A. Sharp, P.Eng. P. R. Knoll, P.Eng. R. T. Liddle, P.Eng. (of Liddle Engineering Ltd.) K. G. Richards, P.Eng. (of Fish Engineering Limited)
Dome Petroleum Limited, Petro-Canada Inc., PanCanadian Petroleum Limited (Straddle Plant Owners) F. M. Saville, Q.C.	K. N. Fernie, P.Eng. T. H. Skupa, P.Eng. (both of Petro-Canada Inc.) W. C. Reinwart (of PanCanadian Petroleum Limited) H.W.G. Petranik, P.Eng. E. L. Forgues, P.Eng. J.B.J. Cochrane, P.Eng. (all of Dome Petroleum Limited)
Dow Chemical Canada Inc., Union Carbide Ethylene Oxide/Glycol Company, Celanese Canada Inc., C-I-L Inc., Novacor Chemicals Ltd. (Petrochemical Producers) R. A. Neufeld	A. J. Branecky (of Celanese Canada Limited) Dr. J. E. Feick, P.Eng. (of Novacor Chemicals Ltd.) Dr. J. M. Hay, P.Eng. (of Dow Chemical Canada Inc.) Dr. T. R. Jones (of Union Carbide Ethylene Oxide/Glycol Company) J. G. Clarke (of C-I-L Inc.)
Alberta Gas Ethylene Company Limited (AGEC) F. R. Foran	R. Bowser, P.Eng. Dr. J. E. Feick, P.Eng. D. Ferries, P.Eng. Dr. R. Wright Dr. R. Mansell (both of Wright-Mansell Research Limited)
ATCOR Resources Limited D. M. Murray, P.Eng. D. E. Belsheim, P.Eng.	
Esso Resources Canada Limited (Esso) W. M. Samoil	

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Energy Resources Conservation Board staff H. R. Hansford K. Johnston B. C. Hubbard, P.Eng. L. S. Fillion, C.E.T.	

The following sections describe in some detail the applicant's and interveners' views on these issues, summarize the Board's assessment, and provide the Board's findings, conclusions, and decision.

3 THE APPLICATION

Anderson calculated that its proposed plant would, over a 20-year operating period, recover some 965 x 10^3 m^3 of ethane that would be incremental to that otherwise recovered in the province. The calculation was based on a 96 per cent ethane recovery efficiency, which Anderson believed would be technically and economically feasible to achieve at its proposed plant.

The calculation also assumed that 80 per cent of Anderson's Dunvegan gas would be reprocessed at the Empress straddle plants and 20 per cent would be reprocessed at the Cochrane straddle plant. Anderson stated that this was based on conversations with ANG staff, but agreed with interveners that there is considerable uncertainty in trying to determine the split of Dunvegan gas between the eastern pipeline system which routes gas past Empress and the western system which flows gas past Cochrane.

Anderson also commented on the ANG contention that the level of ethane recovery at Dunvegan would be restricted by Anderson's contract with the gas purchaser, Alberta and Southern Gas Co. Ltd. (Alberta and Southern). The contract specifies a minimum heating value of 1000 British thermal units per standard cubic foot (Btu/scf)[1] for the sales gas. Anderson stated that it was confident it could obtain relief from the minimum heating value requirement through renegotiating its contract with Alberta and Southern and would be able to realize state-of-the-art ethane recovery capability at its proposed plant. Anderson also said that if it was unable to renegotiate its contract with Alberta and Southern, another alternative would be to process additional volumes of gas at the existing plant but not at the proposed facility such that the combined sales gas from both would meet the minimum heating value requirement.

With respect to present and future markets for ethane, Anderson stated that it had arranged a contract with Esso for the sale of all the ethane-plus liquid to be produced at the proposed Dunvegan facility for a 20-year term. Anderson contended that while the overall ethane supply/demand balance might be of concern to the Board, it should not affect consideration of the application because the contract with Esso demonstrated that the ethane-plus liquids would be meeting some portion of Esso's demand for miscible flood solvent.

Anderson addressed the matter of provincial ethane supply and demand by submitting forecasts of each. Generally, Anderson expected that demand would exceed supply from approved sources over the 10-year forecast period. Supply would peak in 1988 at some 28 x 10^3 m^3/d and demand (combined petrochemical feedstock, export, and miscible flood solvent) would peak at some 35 x 10^3 m^3/d in 1991. Notwithstanding that its overall supply/demand balance showed an ethane shortage, Anderson stated that ethane available to AGEC from the straddle plant system would be sufficient to meet the feedstock requirements for a third ethylene plant. Such a plant would therefore not be jeopardized by approval of Anderson's application.

Anderson calculated that its cost of producing ethane at Dunvegan would be \$39.17/m^3 at 85 per cent ethane recovery efficiency as stated in the application and \$37.21/m^3 at 96 per cent ethane recovery as proposed at the hearing. Both cost figures include transportation to Fort Saskatchewan and fractionation but are exclusive of shrinkage. Anderson compared its costs with those of previously approved field plants and suggested they were within the same range. Anderson

[1] Metric equivalent used throughout remainder of report is 37.43 megajoules per cubic metre (MJ/m^3).

further stated that its ability to arrange a contract for the sale of its liquids clearly demonstrated the competitiveness of producing those liquids at the proposed Dunvegan facility.

Anderson conceded that its proposed plant would have a negative impact on the Alberta petrochemical industry and the existing straddle plant system by causing increased feedstock and operating costs. As well, Anderson said that the reduced ethane production at the straddle plants due to the field deep-cutting of the Dunvegan gas would result in reduced export sales through the Cochin pipeline system. This, combined with the increased feedstock costs, would result in a net cost discounted at 15 per cent to the petrochemical industry of $9.6 million over 20 years. (Anderson's calculations were based on 85 per cent ethane recovery at Dunvegan with 80 per cent of Dunvegan's sales gas being reprocessed at Empress and 20 per cent being reprocessed at Cochrane.) Anderson said this would represent an overall impact of less than 1.5 per cent on feedstock costs to the petrochemical industry.

Notwithstanding its calculated negative impact on the petrochemical industry, Anderson argued that, to the extent that AGEC has reinjected into gas leaving the province some 6.7 million barrels (1100 x 10^3 m^3) of ethane produced at the straddle plants over the last 3 years, any calculated increase in the unit cost of producing ethane at the straddle plants due to upstreaming would only be "notional".

Anderson also calculated that its proposed plant would cause a negative impact discounted at 15 per cent of $47.4 million on the straddle plant owners. This cost would result almost entirely from the reduced amount of propane-plus liquids available to the straddle plants because of the propane-plus recovery at Dunvegan. Anderson noted that, in the past, the Board had recognized such to be the right of the field plant owners.

Using a 15 per cent discount rate, Anderson calculated its after-tax net revenue from the proposed expansion to be $19.7 million. In addition, by assuming the existing marginal tax rate applied, some $32.2 million and $31.8 million would accrue to the federal and provincial governments, respectively. Net benefits to other gas producers were calculated to be $3.3 million and if the expansion were to result in the construction of additional oil pipelines, the oil producers in the region would benefit by $6.8 million.

After deducting negative impacts on the petrochemical and straddle plant industry, Anderson calculated overall net benefits to society of $17.2 million if its project were to proceed.

Although Anderson did not quantify the benefit it believed would accrue through increased potential for enhanced oil recovery schemes, it stated that the enhanced oil recovery market is best served by ethane-plus supplied from highly efficient, suitably-sized plants such as the one proposed.

Anderson expressed its opinion that a gas producer's proprietary rights are an integral part of the public interest and are not of secondary importance. For its application, Anderson stated that exercising its proprietary right would also meet the overall public interest and result in the conservation of Alberta's resources.

4 THE INTERVENTIONS

While AGEC generally agreed with the methodology used by Anderson in calculating the amount of incremental ethane production that would result from the proposed facility, ANG and other interveners questioned Anderson's assumptions regarding ethane recovery at Dunvegan and the split in the flow of Dunvegan residue gas between Empress and Cochrane.

ANG argued that, even though Anderson's proposed plant might be capable of achieving an ethane recovery efficiency of 96 per cent, Anderson's contract with the purchaser of its residue gas, Alberta and Southern, would require Anderson to maintain a minimum heating value of 37.43 MJ/m^3 in its sales gas. This requirement would result in Anderson effectively being restricted to recover only some 68.5 per cent of the ethane in its gas.

ANG further stated that relief from the heating value specification contained in the contract was not simply a matter to be negotiated between Anderson and Alberta and Southern because Alberta and Southern in turn had contractual commitments to ANG to endeavour to maintain a high concentration of ethane in the feed gas to the Cochrane straddle plant. As a party to those negotiations, ANG said it would not allow Alberta and Southern to purchase gas from Anderson's Dunvegan plant that did not meet the minimum heating value specification.

ANG also disagreed with Anderson's assumption that 20 per cent of the Dunvegan gas is reprocessed at the Cochrane staddle plant and 80 per cent is reprocessed at Empress. ANG attempted to determine the split between Empress and Cochrane by reviewing NOVA's (NOVA, AN ALBERTA CORPORATION) records of

operation of its western system for an 8-month period (specifically the transfer of gas from the western system to the eastern system at the Ferd exchange). From this review, ANG concluded that 58 per cent of the Dunvegan gas flowed to Cochrane and 42 per cent to Empress over the period studied. Because of the higher level of ethane recovery at Cochrane compared with Empress, ANG believed that Anderson's assumption that only 20 per cent of its gas was going to Cochrane caused Anderson's calculation of incremental ethane to be too high.

The interveners, primarily AGEC, suggested that there is not presently and would not be in the future any need for the incremental volume of ethane that could be produced at Dunvegan. AGEC's forecast showed that for the next 10 years, ethane supply from the straddle plant system and approved field facilities will be more than adequate to meet petrochemical and miscible flood solvent demand.

AGEC said that its forecast surplus of ethane clearly indicated that any ethane produced at Dunvegan for sale to the miscible flood market would simply back out an equivalent amount of ethane from some other existing or approved source. AGEC stated that it would make all ethane that is surplus to its requirements available for sale (its requirements being petrochemical demand and the minimum 25 000 barrel per day (3975 m^3/d) Cochin export). However, straddle plant owners Dome and Petro-Canada both acknowledged that efforts to market ethane that is currently surplus to petrochemical and export requirements to miscible flood operators has met with limited success.

The interveners disagreed with Anderson's position that its contract with Esso for the sale of its liquids demonstrated a need for the proposed plant. They suggested that the contract was of little value to the Board in assessing ethane supply and demand to determine if facilities to produce incremental volumes are required.

There was no suggestion that Anderson's stated cost of producing ethane at Dunvegan was incorrect nor that it was not competitive. Straddle plant operators stated that, if markets for ethane develop such that additional extraction is required, the Empress No. 1 plant could be expanded to recover an additional 1100 m^3/d of ethane at a cost of \$17.30/m^3 or alternatively, an additional 1900 m^3/d at a cost of \$37.48/m^3. Petro-Canada said its Empress plant could be expanded to recover an additional 1600 m^3/d at a cost of \$24.53/m^3.

AGEC's economic analysis showed that Anderson's project would cost the petrochemical industry some \$12 million over 20 years discounted at 15 per cent. The factors contributing to this loss would be increased unit ethane cost, lost revenue from the ethane that would no longer be available for export sales, and the cost of purchasing ethane from outside the straddle plant system in the future to meet the requirements of a third ethylene plant. As well, AGEC calculated that the cumulative negative impact on the petrochemical industry of upstreaming approved to date and including this application, would be \$906 million undiscounted over 20 years. AGEC also calculated that, due to reduced propane-plus production, Anderson's project would cost straddle plant owners \$47.1 million over 20 years discounted at 15 per cent.

Petrochemical producers stated that the cumulative negative effect of upstreaming on the whole Alberta ethane-ethylene petrochemical project has become so significant that it is now one of the major factors that will determine whether or not the Alberta petrochemical industry can export its products. They further stated that if the Alberta petrochemical industry becomes uncompetitive in world markets, upstreaming projects such as Anderson's will have contributed to a significant loss of jobs, gas markets, and other benefits of the industry's presence.

Petrochemical producers went on to say that at the time of the initial major investments into the petrochemical industry in Alberta, the only cost-effective means of producing a sufficient, secure supply of ethane was the straddle plant system. It was necessary for petrochemical producers to make long-term commitments to the cost of those facilities in order to proceed. Upstreaming therefore can only be viewed as erosion of the feedstock supply necessary to maintain the petrochemical industry in Alberta. They said that approval of the Anderson application following the recent approvals of others for upstreaming would be a clear sign to potential petrochemical investors that ethane from Alberta's natural gas cannot be relied on for future petrochemical development.

With respect to the impact of Anderson's proposed plant on the potential for enhanced oil recovery, the interveners suggested that given the surplus supply situation as forecast by AGEC, any impact would be minimal. If Anderson's ethane-plus liquid did not become available, miscible flood operators could obtain it from other already approved sources.

Since those interveners who addressed economic matters supported AGEC's methodology and opposed approval of the application, the Board will refer to only AGEC's intervention in this respect.

To determine the economic impact of the proposed project, AGEC made four significant changes to Anderson's economic assumptions. First, the value of the spinoff benefits to other oil producers was eliminated because, according to AGEC, the capital costs of extensions to the Peace pipeline should be allocated among all the prospective users of the extension. Second, the alternative production schedule for makeup gas was advanced from the period 2005-2023 to 1995-2013. Third, only one-half of federal taxes were considered to be an Alberta benefit and, fourth, the value of an AGEC sale of ethane down the Cochin pipeline included the Cochin tariff. These adjustments showed the project would result in an overall net cost of $14.4 million. Assuming an excess supply of ethane, AGEC calculated that these net costs would increase to $34.2 million. In what it referred to as a "traditional" benefit/cost analysis, AGEC calculated a net cost of $12.2 million. It also suggested that "leakages" such as the financial flows to non-resident owners should be considered in a benefit/cost analysis although it had not done so in its analysis.

AGEC maintained that proprietary rights of producers are of secondary importance compared to other aspects making up the overall public interest. It said that a producer's proprietary right to ethane as a component of its gas stream should not lead to approval of facilities to extract and dispose of that ethane without demonstrating that to do so would be in the public interest. The petrochemical producers also noted that in any event, Anderson's proprietary rights were restricted by its contract with Alberta and Southern for the sale of its gas.

No interveners commented specifically on the degree of upgrading of resources within Alberta or the conservation and environmental aspects of the project.

5 THE BOARD'S ASSESSMENT

5.1 Incremental Ethane and Other Liquids

The Board has considered the evidence presented respecting the calculation of incremental ethane, and in particular, how it would be affected by the split in the flow of Dunvegan gas between Empress and Cochrane and by the ethane recovery efficiency assumed to occur at Anderson's proposed plant.

The Board believes the most accurate estimate of the split in flow was that presented by ANG, which suggested 58 per cent of Anderson's Dunvegan gas presently flows to Empress in NOVA's eastern system while the remaining 42 per cent flows to Cochrane in NOVA's western system. While the Board accepts that these numbers are an indicator of the situation over the 8-month period studied by ANG, it believes that the split would be subject to fluctuations on a day-to-day basis and possibly over the longer term. Given the results of the ANG study and the considerable uncertainty expressed by all parties at the hearing as to the split, the Board believes it is reasonable to assume for its calculations that 50 per cent of the Dunvegan gas would be reprocessed at Empress and 50 per cent would be reprocessed at Cochrane.

With respect to the ethane recovery efficiency at the proposed plant, the Board accepts Anderson's evidence that the proposed facility could be designed to recover some 96 per cent of the ethane in the gas. However, it must also recognize evidence that suggests Anderson would be restricted to some reduced levels of ethane and propane-plus recovery because of its existing contract with Alberta and Southern for the sale of the residue gas. Notwithstanding Anderson's contention that its contract was being renegotiated and that it was confident it could obtain relief from the minimum heating value requirement of 37.43 MJ/m^3, the Board does not believe it would be appropriate to speculate on the outcome of those negotiations. In the Board's view, the application must be assessed within the framework of any contractual condition that exists at the time of the Board's consideration of the matter. For this reason, the Board's calculation of incremental ethane assumes that the level of ethane recovery at Dunvegan would be restricted to some 68.5 per cent.

Using the assumptions described above, the Board calculated that the amount of ethane produced from the proposed Anderson facility that would be incremental to that otherwise recovered would be some $443 \times 10^3\ m^3$ over a 20-year period. As well, the Board's calculation shows that only very marginal amounts of the propane-plus production at the proposed plant would be incremental.

5.2 Markets

The Board is satisfied that there are available markets for any incremental propane or heavier hydrocarbons which might be recovered. The availability of markets for the ethane is, however, more uncertain.

Clearly, the amount of incremental ethane that would result from approval of the Anderson facility would be small relative to the total ethane production capability that exists in the province. The Board believes, though, that the significance of any amount

of incremental ethane is dependent on what is expected to occur respecting the potential supply and demand within the province.

With respect to present and future markets for the ethane-plus liquids that would be produced at Dunvegan, the Board believes Anderson's evidence is clear that it has secured a market for its product. The Board believes, however, that it must also look at the overall supply/demand balance for ethane to assess the need for a facility that would produce some amount of incremental ethane.

There was considerable evidence presented by the applicant and interveners respecting the balance between ethane supply and demand in the form of forecasts and also by way of comments respecting marketing of ethane. In assessing the forecasts, the Board notes that Anderson shows a shortage of ethane over the forecast period from 1985 to 1995, while the AGEC forecast shows a surplus over the same period. The Board notes that part of the difference is due to Anderson predicting a smaller provincial supply than does AGEC. This is partly due to lower expected production from field plant sources over all years of the forecast period. The two supply forecasts diverge in the later years of the forecast because AGEC included significant volumes of reproduced ethane in its supply. On the demand side, the two forecasts show similar demand for the petrochemical and export requirements. The miscible flood solvent demand is also similar in magnitude in the early years but AGEC's forecast shows declining demand for miscible flood use after 1988 while Anderson predicts roughly constant demand until the end of the forecast period.

Having regard for the forecasts submitted by AGEC and Anderson, the Board has forecast what it expects will be the relationship between ethane supply and demand for the period 1985 to 1995. This is shown in Figure 1. The Board's ethane supply represents potential ethane supply from currently existing and approved straddle and field plants. Potential ethane supply from the straddle plants is based on the Board's forecast of gas throughput at those facilities and AGEC's forecast of ethane concentration and recovery efficiencies. Ethane supply from approved field plants is generally based on forecasts submitted by the proponents of those facilities when the applications were being considered.

The Board's forecast of potential supply is somewhat higher than AGEC's in the early years but, while the AGEC forecast shows increasing supply throughout the forecast period, the Board predicts that potential supply from approved sources would peak in 1988 and begin to decline thereafter. The Board's forecast of supply does not include as an explicit component, reproduced ethane from miscible flood schemes. The Board believes that, for most of the forecast period, ethane reproduced from initial phases of large schemes will be reused in subsequent phases of the same scheme. To that extent, demand for ethane from external sources for the later phases is also reduced. The Board realizes that beyond the forecast period, as miscible flood demand subsides, volumes of reproduced ethane may become available that could significantly increase supply.

The Board accepts the forecast of ethane demand for petrochemical feedstock prepared by AGEC. With respect to miscible flood demand for ethane, the Board has forecast what it expects to be the volumes of ethane necessary to develop all potential enhanced oil recovery schemes that are now considered technically feasible. The Board's forecast enhanced oil recovery demand is similar to both the AGEC and the Anderson forecasts in terms of peak requirements. The Board expects that miscible flooding would continue to create a demand for ethane for a longer period than forecast by AGEC but not until 1995 at the level forecast by Anderson.

The Board recognizes that there are many factors which may impact on future demand for ethane for miscible flood purposes. These include, among others, fiscal policies of governments, the technology of enhanced recovery alternatives, and the flexibility in the makeup of injectant material. Having regard for the current situation, the Board believes the forecast demand reflected in Figure 1 is a reasonable projection.

In total, the Board's forecasts show that potential ethane supply from existing and approved sources will be sufficient to meet the demand of petrochemical and miscible flood markets until 1990, with volumes left for export which would be equal to or greater than the minimum export demand referred to by AGEC at the hearing. For the years 1991 and 1992, the Board forecast shows that there could be a modest shortfall in terms of the "export demand" but that petrochemical and miscible flood markets within Alberta could be fully supplied.

Regarding the minimum export volume of 3975 m^3/d, it should be noted that existing ethane removal permits would not allow the removal of 3975 m^3/d after 1989 in any event. It is necessary to note, also, that the need for these export volumes is uncertain. Additionally, evidence at the hearing indicated that such exports

only result in economic netbacks to the province which are equal to or less than the value of the ethane in the gas stream.

Given the supply/demand balance shown in Figure 1, the Board believes that the incremental supply from the Anderson project would be of little public benefit for much of the period shown. Given the situation that currently exists, where potential ethane supply is greater than total demand, Anderson's sale to the miscible flood market simply implies a lost sale of the same volume for the straddle plant system or another approved field plant. In short, even though the incremental ethane to be recovered at the proposed plant would be small, there is no "incremental demand" for it.

Further to this question of "incremental demand", it is important to note that the Board's analysis of supply and demand focused on the capability of total supply from existing and approved facilities to meet total demand of all markets. The Board makes no distinction between field plant and straddle plant supply nor between petrochemical, miscible flood and export demand (although there is a clear distinction respecting export demand that is noted later).

The evidence of AGEC and the straddle plant owners clearly indicated that these groups have ethane available in their system that is surplus to petrochemical and a minimum export demand and are willing to make it available to miscible flood operators at competitive rates. Further, the Board notes the absence of any evidence from miscible flood operators stating that they are unable to purchase ethane needed for miscible flood purposes. The evidence at the hearing thus supports the conclusion that there is not an "incremental demand" for ethane. It should be further noted with respect to the minimum export volume claimed for the Cochin pipeline system, that legislation and conditions of the permit granted to Dome for the removal of ethane from the province clearly show that export markets may be served only after Alberta demand is satisifed, including miscible flood demand.

5.3 Cost of the Liquids

With respect to the cost of the ethane produced at Dunvegan, the Board accepts Anderson's evidence that it would be comparable to that produced at previously approved field plants. The agreement between Anderson and Esso indicates that the product is competitive in the miscible flood marketplace. The Board also notes the comments of the straddle plant owners regarding possible expansions of their facilities that could recover much larger incremental volumes of ethane at a lower unit cost than at Dunvegan. Given the apparent ethane surplus in the province, the Board doubts that sufficient markets could be found to warrant the size of expansions suggested by the Empress operators.

5.4 Impact on Straddle Plants and Petrochemical Industry

The Board's assessment of the economic impact on straddle plants that would result from the Anderson facilities is presented in a later section on economic impacts (Section 5.6).

The Board heard considerable evidence, some quantitative and some qualitative, on the impact of Anderson's project on the petrochemical industry. Notwithstanding Anderson's argument that the calculated costs to the petrochemical industry are largely "notional", the evidence is clear that approval of the application would have a negative impact on the petrochemical industry and the cumulative effect of past applications is substantial.

Using the assumptions regarding ethane recovery efficiency at Dunvegan and the split in gas flow between Empress and Cochrane described previously, the Board calculated a cost to the petrochemical industry of some $8.6 million over 20 years discounted at a 15 per cent rate (see Section 5.6).

In an earlier decision on an application to install deep-cut facilities (D 85-4), the Board recognized that the continuing poor business environment of the petrochemical industry at this time makes it necessary to consider the cumulative effects of all upstreaming approvals. In this regard, the Board notes AGEC's evidence that the cumulative impact on the petrochemical industry of upstreaming would total some $906 million (undiscounted) if the Anderson application is approved. The Board agrees with the petrochemical industry interveners that the cumulative impact of upstreaming is considerable and that this is a negative factor which could influence possible future investment by petrochemical producers in Alberta.

5.5 Enhanced Oil Recovery

The Board has considered the impact of the proposed facilities on the potential for enhanced recovery of oil. Given the Board's conclusions respecting the overall supply/demand balance for the province, incremental ethane-plus liquids that would be produced at Dunvegan would not have any effect on enhanced oil recovery.

Equivalent volumes of solvent could be obtained from other approved sources.

5.6 Economic Impacts

The Board's calculations regarding the economic aspects of this application are summarized in Table 2. As it has attempted to do in previous decisions, the Board's analysis ultimately focuses on the value of resources used and produced. In the Board's view, the most significant difference between its method and the "more traditional" approach, argued by AGEC, is in the manner of presentation of the results. The Board has calculated the net value of the change in production by sector within the industry versus AGEC's calculation of the value of the net change in production by the industry. While the former involves a few more steps, the final result is the same when externalities are considered.

The Board believes that the detailed format is desirable in this instance because it reflects the interests of all parties affected by the decision by showing those who reap benefits and those who bear costs. For example, both Anderson and AGEC indicated that non-resident shareholders' income should not be considered relevant from the provincial perspective. If the Board were to adopt this view, the calculation would have to proceed from a breakdown of the changes in corporate income by industry group or company. Notwithstanding its reservation of applying the more "traditional" approach in this situation, the Board has calculated, later in this section, the impact of such an analysis.

The Board calculated the value of liquids based on the deemed value of fractionated products at Fort Saskatchewan. As supported by the evidence, the value of fractionated ethane was assumed to approximate 67 per cent of the value of fractionated propane.

The Board adopted Anderson's estimate of $12.5 million for construction costs. The Board does not believe that the reduced liquids recovery factors assumed in its analysis would materially affect the capital costs of the on-site facilities. To arrive at the other costs attributable to this project, (electricity, other operating costs, transportation of liquids to Fort Saskatchewan, and deemed fractionation costs) the Board endeavoured to differentiate between the marginal costs of providing these services and the actual tariff which Anderson or others would expect to incur. The difference between the tariffs and marginal costs amounts to a profit margin which would, presumably, be shared by those providing the services and those using them. These marginal costs have been charged against the expected income from the proposed expansion and would not affect the final analysis.

The Board believes that combined incremental capital costs for pipeline extensions and Anderson's pro rata share of a fractionation facility would be about $7.0 million. Thus, the total capital costs associated with the proposed expansion were estimated to be $19.5 million. After adjusting Anderson's estimates of plant operating costs, transportation tariffs and fractionation costs to differentiate between administered tariffs and marginal costs, the Board calculated the pre-tax net value of the proposed expansion would be some $20.4 million.

The Board continues to believe that one of the relevant costs to the petrochemical industry would be the economic efficiency loss of ethane extraction at straddle plants due to a leaning of the inlet gas. As well, the costs to the petrochemical industry of foregone sales opportunities for its surplus ethane is another relevant factor. On the latter issue, and having regard for its views on the overall supply/demand situation (Section 5.5), the Board believes that ethane to be produced by Anderson and sold to enhanced oil recovery users would merely displace ethane that is readily available from other sources, particularly AGEC. The evidence suggests that ethane can and would be made available from AGEC's sources under terms and conditions similar to those that would apply to other sources. Alternatively, AGEC would be forced to export surplus ethane or reinject it into the gas stream. Since the Board believes Cochin export sales of ethane have a net value of approximately zero, this is not viewed as an appropriate alternative. The Board calculated the burden of the cost-of-service effect to be about $10.0 million, while the foregone sales opportunity for surplus ethane would be some $4.5 million.

The costs to the straddle plant sector were estimated to be some $37 million. These costs were calculated as the value of foregone propane and butanes less shrinkage and transmission costs. As in previous Board analyses, this provides for adequate treatment of the relatively fixed operating costs and sunk capital costs at the straddle plants.

The Board believes there would be some accelerated gas production resulting from the deep-cutter's effective leaning of the gas stream leaving the straddle plants. This provides a net present value of $9.2 million assuming that the gas would otherwise have been sold over a 10-year period commencing in 1995.

Despite the argument by Anderson, the Board does not believe that this project would affect the decision

to extend the Peace pipeline to accommodate oil producers in the region. The Board appreciates, however, that if the Dunvegan project were to proceed, a larger diameter line could be built to accommodate the Anderson volumes. The Board estimated that the efficiency gains, in terms of savings in unit operating costs of a larger pipeline versus a smaller one, would have a present value of some $60 thousand over the life of the project.

By assuming a marginal tax rate for all the affected parties, the Board analysis shows that the provincial income would increase by some $0.9 million while federal revenue would decline by $6.0 million. Considering that some companies affected by the proposed plant would not be in a taxable position for some time during this period, the public impact is overstated.

Notwithstanding the tax effect, the analysis shows that the project would result in an overall net cost of some $21.8 million to society at large.

The Board modified the components of Table 1 to reflect the narrower framework of Alberta's public interest that was suggested by Anderson and AGEC. Both parties acknowledged that adjustments should be made to the federal tax calculations and corporate income estimates to exclude the portions not directly relevant to Alberta. In this context, the Board believes that most if not all federal taxes should be excluded. The notion advanced by AGEC that 50 per cent of federal taxes may be relevant to Alberta is not convincing. The Board does not believe there is any functional relationship between a marginal change in provincially-sourced federal income taxes and a marginal change in provincially-expended federal revenues. Even though an average relationship may exist, the Board believes this would be more by coincidence than by design. Further, such a methodology assumes that any expenditure made within Alberta by a non-resident, government or corporate, is a net benefit to Alberta in and of itself, without having to recognize any other factors. This is not in keeping with the Board's benefit/cost methodology.

The Board also believes that corporate profits accruing to non-Alberta residents would have to be considered. The Board believes that a reasonable estimate of Alberta residents' equity participation in the Dunvegan Field would be 50 per cent. A representative number for the combined petrochemical and straddle plant sector might be 10 per cent. Accordingly, if these factors are applied to the after-tax corporate gains and losses, the proposal would show a modest benefit to Alberta rather than the substantial net cost identified in Table 2.

In these particular circumstances the Board is not comfortable with this restricted view of Alberta's public interest, nor has it taken such a view in previous deep-cut applications. It seems to the Board that previous corporate decisions to acquire assets in Alberta, in all segments of industry, were made in good faith with the expectation that impartial treatment would be accorded the owners of the facilities. Therefore, in these circumstances the Board does not believe it would be proper to discriminate between resident and non-resident shareholders.

The Board's analysis leads it to conclude that the overall economic impact of the proposed Anderson project would be negative.

5.7 Other Issues

The Board maintains the same position with respect to producers' proprietary rights that it has expressed in previous decisions, that being that proprietary rights are but one aspect of the overall public interest. In applications of this nature where there are considerable negative impacts to parties that form another aspect of the public interest, proprietary rights must be considered in light of those impacts. As implied in previous decisions, it is the Board's opinion that in these cases of upstreaming, preservation of the producers' proprietary rights could also be achieved by negotiating alternative arrangements with the affected parties in a manner such that the producers received some financial recognition of these "rights".

The Board generally considers that, because of the incremental ethane that is recovered by projects such as proposed by Anderson, these projects contribute to the degree of potential upgrading of resources within Alberta. In this situation, however, where the evidence indicates there is a surplus of ethane to the extent that some of it is reinjected into the gas leaving the province, there is little benefit from upgrading.

With respect to the conservation and environmental aspects of the proposed facilities, the Board notes that Anderson's proposal is for a highly efficient plant in terms of hydrocarbon recovery levels and that it would meet all provincial environmental standards.

6 FINDINGS AND CONCLUSIONS

- Anderson's project would recover a minimal volume of ethane and propane incremental to the already approved potential supply. This is largely due to the relatively low ethane concentration in the Dunvegan

gas and because of the contractual restriction on the level of natural gas liquids recovery.

- Any incremental propane and heavier hydrocarbons can be readily disposed of.
- The overall supply/demand balance for ethane in the province suggests that there is no need in the foreseeable future for the incremental volume that would be recovered.
- The cost of the ethane produced at Dunvegan would be competitive in the miscible flood marketplace with ethane from other approved sources.
- The cumulative impact of upstreaming on the Alberta petrochemical industry is one of several factors affecting its competitiveness in international markets.
- The incremental liquids that could be recovered at Dunvegan would have little impact on the potential for enhanced recovery of oil since sufficient supply could be obtained from sources already approved.
- Anderson's proposed project would result in benefits to itself, enhanced oil recovery operators, gas producers, oil producers in the Dunvegan region, and the Provincial Government amounting to some $14.6 million over a 20-year period and at a 15 per cent discount rate. On the other hand, it would have a negative impact of some $36.4 million on the petrochemical industry, straddle plant owners, and the Federal Government. This would result in a net cost of $21.8 million (over 20 years discounted at 15 per cent) to society.
- Approval of the application would result in the preservation of Anderson's proprietary rights to its liquids.
- The degree of upgrading of resources within Alberta would be minimal if any.
- The proposed plant would meet conservation requirements and environmental standards.

Based on the analysis of all the evidence presented and the above findings, the Board believes that it should deny the Anderson application. In the Board's opinion, the positive aspects of the application from the provincial perspective are outweighed by the negative. Indeed, this is reflected in the "net public cost" of approval of the application.

Referring specifically to the ethane recovery component of the proposal the Board believes that, although a small amount of incremental ethane production would be provided, because of the surplus ethane situation that currently exists that incremental volume would have little value to the province. From a provincial perspective, approval of Anderson's application would therefore only serve to transfer revenue from one group of owners to another by duplicating existing facilities without providing any net benefit. This, coupled with the cumulative negative impact of previously approved upstreaming applications on the petrochemical industry in its continuing depressed state, leads the Board to its conclusion to deny the application.

The Board recognizes that the criteria on which this decision is based involve factors such as supply, demand, and product prices which are variable with time and prevailing circumstances. As indicated in previous decision reports, any future upstreaming application would be judged on its own merit and the circumstances at the time of consideration.

Again referencing earlier decision reports, the Board wishes to emphasize that it continues to strongly endorse the concept of recovery of liquids at either field plants or straddle plants or a combination of them which would be optimum in the public interest. It continues of the view that if this is to occur, producers must be given some financial recognition of the liquids extracted from gas they produce.

7 DECISION

The Board is not prepared to approve Application 850205 by Anderson Exploration Ltd. to install facilities to extract ethane-plus liquids from gas processed at its existing Dunvegan gas plant.

F. J. Mink, P.Eng., Acting Board Member, concurs with the contents and with the issuance of this report.

DATED at Calgary, Alberta, on 14 August 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman, P.Eng.
Board Member

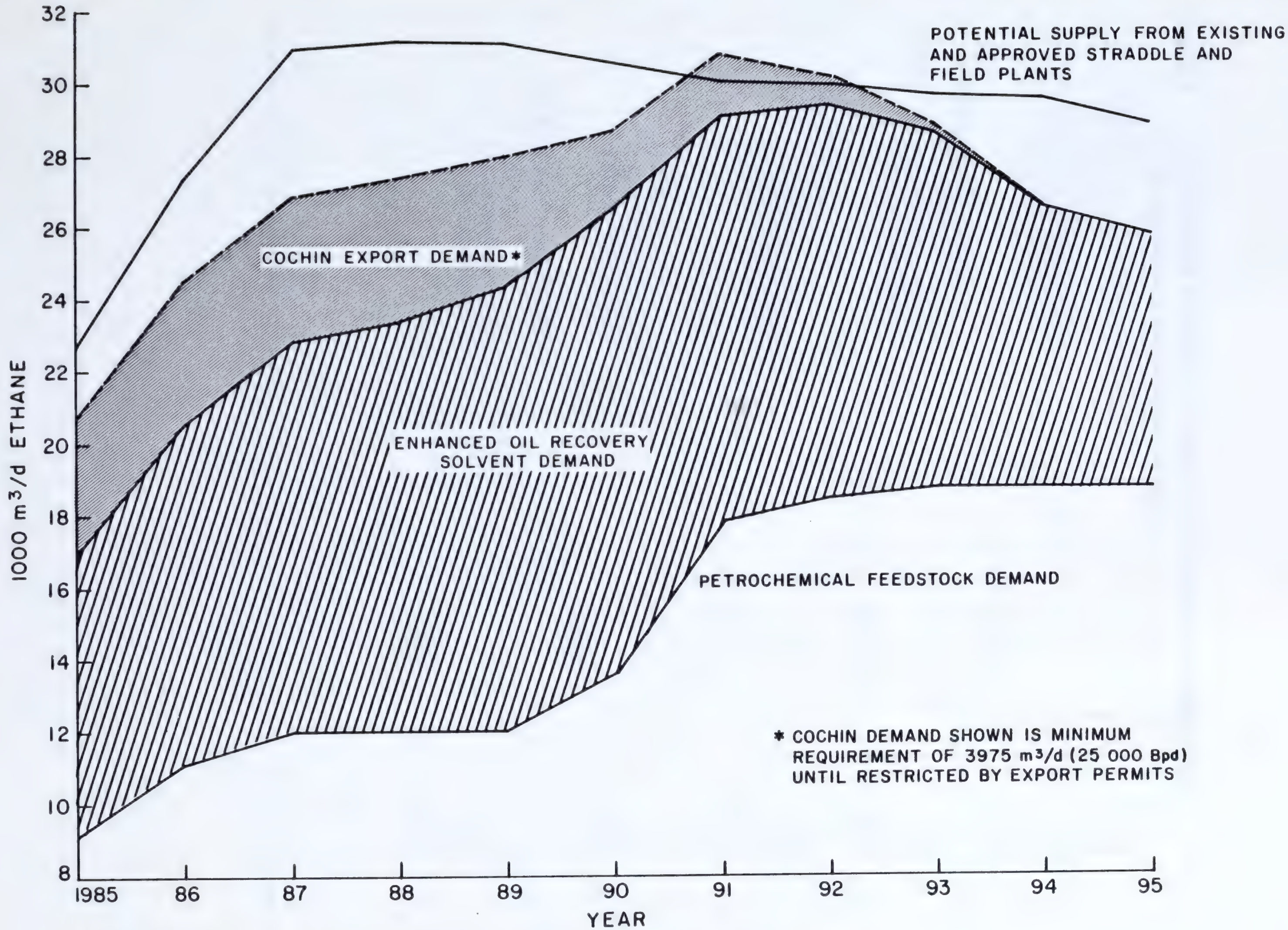


FIGURE 1
ALBERTA ETHANE SUPPLY AND DEMAND AS FORECAST BY ERCB.

D85-33
ERCB

TABLE 2 NET BENEFITS AND COSTS OF PROPOSED ANDERSON DEEP-CUTTER
(15 per cent discount rate, discounted to 1985)

			$\$ \times 10^6$
1.	Field Plant Owners/Enhanced Oil Recovery		
	a) industry		12.0
	b) provincial government		2.3
	c) federal government		6.1
		Subtotal	20.4
2.	Petrochemical Industry		
	a) industry		(8.6)
	b) provincial government		(1.6)
	c) federal government		(4.3)
		Subtotal	(14.5)
3.	Straddle Plants		
	a) industry		(21.8)
	b) provincial government		(4.1)
	c) federal government		(11.1)
		Subtotal	(37.0)
4.	Gas Producers		
	a) industry		1.6
	b) provincial government		4.3
	c) federal government		3.3
		Subtotal	9.2
5.	Oil Producers (Transportation)		
	a) industry		
	b) provincial government		0.06
	c) federal government		
		Total	(21.8)

Calgary Alberta

MANALTA COAL LTD. CORDEL AREA APPLICATION FOR REPLACEMENT OF MINE LICENCE NO. C 84-18

Decision D 85-34
Application 850327

1 INTRODUCTION

1.1 The Application

Pursuant to section 11 of the Coal Conservation Act, Manalta Coal Ltd. (Manalta) applied for a replacement licence to continue mining at the Vesta Mine (Mine No. 1046/01) in township 40, ranges 15 and 16, west of the 4th meridian.

1.2 The Hearing

A public hearing of the application took place on 6 and 7 June 1985 in Calgary, with N. A. Strom, P.Eng., C. J. Goodman, P.Eng., and H. J. Webber, P.Eng., sitting.

A list of those who appeared at the hearing is given in the following Table.

2 BACKGROUND

Permit No. C 76-63 and Licence No. C 76-48 authorizing coal mining operations at the Vesta Mine site were granted by the Energy Resources Conservation Board (Board) to Manalta on 8 March 1976. Licence No. C 76-48 was subsequently replaced by Licence No. C 79-7 in March 1979 and carried an expiry date of 27 March 1984.

In May 1979, Chinook Management Ltd. (Chinook) applied for and was granted a licence to drill a well in legal subdivision 6, section 13, township 40, range 16, west of the 4th meridian (the 6-13 well). The well was drilled in June of the same year and encountered Basal Quartz gas. The well was subsequently completed but has remained shut in pending the acquisition of a sales contract.

Manalta applied to the Board on 22 February 1984 to continue mining within the bounds of Permit No. C 76-63. The Board granted Licence No. C 84-18 but as a condition required the submission of information, prior to 31 March 1985, respecting the effect of the 6-13 well upon the 5-year mining plan and alternative mining schemes that would allow production from the well.

In fulfilling the conditions of Licence No. C 84-18, Manalta presented a preferred "Base Case" plan, which proposed "mining through" the 6-13 well with the need to either temporarily or permanently abandon the well by 1990.

Manalta also presented three alternative mining proposals (ie, JN1, JN2, JN3), each of which would delay interaction with the 6-13 well until 1996, 2006, and 1992 respectively, but would incur increases of 5 per cent, 5 per cent, and 1 per cent respectively in annual mining costs compared to the "Base Case" plan.

All of the mining schedules utilized the minimum tonnages of coal as contracted with Alberta Power Limited (APL) for the Battle River Generating Station.

In addressing the Licence No. C 84-18 conditions, Manalta also described the procedures which could be used in mining around the well and leaving a protective pillar. An additional cost of $360 000 was identified for these procedures which would leave 55 000 tonnes of coal in the protective pillar.

3 POSITIONS OF THE PARTIES

3.1 Manalta

Manalta as operator of the Vesta Mine stated its position as considering it should be allowed to mine in accordance with the "Base Case" plan and that Chinook should be required to temporarily abandon the 6-13 well so that mining could proceed through the well location without interruption.

3.2 APL

APL is the lessee of the coal rights in section 13, township 40, range 16, W4M, and the holder of the surface rights subject to certain easements.

APL did not disagree with Chinook's right to produce the gas underlying section 13, but expressed concern for any extra costs incurred by the gas well interfering with mining and passing these costs on to the electricity consumers of Alberta.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Manalta Coal Ltd. (Manalta) A. L. McLarty	G. D. Chapel, P.Eng. J. R. Morgan, P.Eng. T. Jenish
Alberta Power Limited (APL) C. K. Sheard	J. C. Gunn, P.Eng. R.K.M. Bellows, P.Eng.
Chinook Management Ltd. (Chinook) T. H. Ferguson	J. Ballachey R. A. Nicholson, P.Eng. G. D. Metcalfe, P.Eng.
Fording Coal Limited (Fording) J. D. Rooke L. Malkin	J. L. Popowich, P.Eng.
Roy Edward Haeberle, Melvin James Haeberle, and Jack Dallas Haeberle (the Haeberles) R. W. Sloan, Q.C.	Melvin James Haeberle
Luscar Ltd. (Luscar) G. D. Watkins	L. Lafleur, P.Eng.
Energy Resources Conservation Board staff (Board staff) C.J.C. Page K. Jamil, P.Eng. D.I.R. Henderson, P.Eng. T. J. Pesta, P.Eng. G. D. Agnew	

3.3 Chinook

Chinook, in the capacity of operator of the well, expressed the belief that the gas and coal resources should both be marketed with as little adverse effect on the other as possible.

It suggested that the Board give consideration to the JN3 mining alternative discussed in the Manalta application.

3.4 Fording Coal Limited (Fording)

Fording is the lessor of the coal rights in section 13 and as such receives royalties on the mined coal.

Fording expressed support for Manalta's "Base Case" plan. Concern was indicated for any alternative mining which involved leaving a protective pillar around the 6-13 well. This would incur, in Fording's opinion, sterilization of the coal in the pillar and would result in loss of royalty revenue by Fording.

3.5 Haeberles

The Haeberles have a royalty interest in gas production from section 13. A wish was expressed to see gas production proceed as soon as possible and without interruption to ensure that royalty payments would be obtained while they could still enjoy them.

3.6 Luscar Ltd. (Luscar)

Luscar operates the Paintearth Mine which is located adjacent to Manalta's Vesta Mine.

Concern was expressed about a pipeline and meter station, proposed by Chinook in connection with the 6-13 well, which would be located on the site of the Paintearth Mine. Luscar took the position that Manalta should be allowed to go ahead with the "Base Case" mining plan.

4 THE ISSUES

The Board considers the principal issues respecting this application to be

- timing of acquisition of interests and preferential access to the resources,
- the reserves and deliverability forecast for the 6-13 well,
- conflict between the coal and gas developments,
- achieving orderly, efficient, and economic development.

5 TIMING OF ACQUISITION OF INTERESTS AND PREFERENTIAL ACCESS TO THE RESOURCES

Manalta acknowledged the right of Chinook to produce gas from the 6-13 well but implied that preferential access should be given to development of the coal resource. It noted that the coal mining permit was approved by the Board and that mining operations had been under way for several years in accordance with the mine licence prior to the time the well was drilled. The mining plan was public information and would have been available for review by Chinook, had it chosen to do so, at the time Chinook applied for the well licence.

Chinook considered that both it and Manalta had equivalent right of access to develop the two resources (gas and coal) and that preferential status did not exist.

Fording expressed the opinion that, in these particular circumstances, the coal mining operations should have priority over the production of gas.

The Board notes that, although the mine permit and conceptual mine sequence were established prior to the well being drilled, Chinook obtained a well licence and a surface lease in order to drill its well. Therefore, while there is a need for access at some time or other for each mineral resource development to occur, the Board doubts that a clear right of preferential access exists. The Board therefore concludes that it is in the public interest to seek a practical means to allow orderly, efficient, and economic development of both the coal and gas resources in the lands in question.

6 THE RESERVES AND DELIVERABILITY FORECAST FOR THE 6-13 WELL

Using information supplied by its consultants, Chinook confirmed that the well was projected to be capable of meeting the sales agreement for the first 2 years but deliverability would reduce after 1987 if remedial measures to enhance deliverability were not then implemented. Chinook was optimistic that sustained production capability could be prolonged despite the close proximity of the gas/water interface to the well perforations. But, failing that and accepting the current forecast, the well could be produced on an economic basis until 1993.

Manalta questioned the deliverability of the 6-13 well and the forecasts of the ability of the well to meet the terms of the Sulpetro agreement beyond 1987.

The Board accepts the Chinook evidence respecting gas reserves, deliverability, and life expectancy associated with the 6-13 well, but notes the distinct possibility that by 1990

(a) the well may be abandoned, or

(b) there may be insufficient reserves in the pool to warrant plug-back and production resumption costs, or

(c) there could be viable remaining gas reserve which would warrant further drilling development of the gas pool.

In the Board's view, forecasting deliverability from the 6-13 well is subject to a wide range of possibilities. This uncertainty renders very speculative estimates of the time when gas production rates would become uneconomic. Perhaps it could be as soon as 2 years after commencing production or as lengthy as 10 years. It is evident, however, that commencement of gas production and at the maximum rate feasible obviously would reduce the potential for conflict. The Board therefore endorses all reasonable effort to commence gas production as soon as possible.

7 CONFLICT BETWEEN THE COAL AND GAS DEVELOPMENT

Manalta submitted that, under its "Base Case" plan and at the anticipated coal production rate, the mining operations would not need to interfere with production from the Chinook well until 1990. It proposed that Chinook would then plug back the well so that mining could continue through the well site. The wellbore could be re-entered after mining (including backfilling) of the well site was completed. Manalta said that it considered any costs incurred in plugging back and re-entering the well should be borne by Chinook.

Chinook advised that gas from the 6-13 well would be sold under a 6-year renewable gas supply agreement with Sulpetro Limited with deliveries to commence 1 November 1985. The 18-month interruption to gas production, which would occur if Manalta's "Base Case" mine licence plan were approved by the Board, would not be acceptable to Chinook as it would defer gas production revenue and could result in the Sulpetro agreement not being renewed. Chinook instead would prefer a mining plan which would provide for mining around the well site, leaving a protective pillar so that Chinook could continue to produce gas, essentially without interruption, to meet the terms of the agreement.

Chinook stated that it would be interested in a mining plan which would delay interaction with the well and the pipeline until 1992. This would provide the time to achieve a payout on the well and the associated gas plant. Further gas production beyond 1992 would depend upon the gas reserves remaining at that time.

Fording said that any plan involving mining around the well and plant surface facilities would effectively sterilize coal, as it was unlikely that the relatively small tonnage left as a pillar around the well would be economic to mine on its own. This would result in loss of royalty revenue to Fording. For this reason, Fording supported the adoption of Manalta's "Base Case" proposal.

APL also expressed support for the "Base Case" plan and concern about increased mining costs associated with the adoption of any other mining plan. It noted that such costs would ultimately have to be borne by the electricity users of Alberta.

Luscar observed that the meter station and pipeline lateral required to deliver the Chinook gas to market would be located within the mine permit area for the adjoining Paintearth Mine. At Paintearth's maximum contract tonnages with APL, Luscar anticipated that any interaction between the mining and the pipeline meter station facilities would not occur before 1992. If APL took the minimum contract tonnages from the Paintearth Mine, then the interaction would be delayed until 1994.

The Board concludes that, unless the gas well can be produced to depletion before 1990, a period of conflict between the mine development and gas well production is bound to occur. The conflict could be delayed by 2 to 5 years if an alternative mining plan were adopted, but at increased mining costs.

While there is reasonable certainty respecting the extent of the coal resource and optimization of planning for coal development, the same is not the case for the gas resource. The Board concludes that the "Base Case" plan as submitted by Manalta is near optimum from a mining viewpoint and should only be modified to the extent warranted after considering the costs and benefits related to optional methods of developing the gas resource.

8 ACHIEVING ORDERLY, EFFICIENT, AND ECONOMIC DEVELOPMENT

The Board recognizes that to achieve orderly, efficient, and economic development of the resources, it is essential that the developments proceed concurrently while minimizing the costs associated with the conflict that might occur during and after 1990.

While the ability to produce the coal resource in the quantities required by the Manalta contract with APL is well established, there is much doubt regarding the period of years that economic gas production rates can be sustained from the 6-13 well. If the well were to water out prior to the mining operation reaching it, then there would be no conflict and no need for a ruling now.

The Board concludes that there is considerable merit in allowing both developments to proceed in accordance with current plans and continue until mining approaches the 6-13 well site. An evaluation of the remaining gas reserves could then be made with a view to establishing the economics of further production and then

1) temporarily plugging or abandoning the 6-13 well to allow mining to progress through, or
2) permanently abandoning the 6-13 well and replacing it by drilling a new well to intersect the same reservoir, or
3) mining around the 6-13 well site.

A sharing of costs by Manalta and Chinook if and when conflict occurs would appear necessary, but it is premature to estimate what those costs would be or the most reasonable arrangements for sharing them.

The Board believes that, to reduce the degree of potential future conflict with the mine development, Chinook, in finalizing its development plans, should locate the required gas processing facilities off the southwest quarter of section 13 and away from mineable coal lands. This would result in increased costs to transport the sour gas production from the lease to

the gas processing facility and the Board believes Manalta should contribute towards these costs.

New easements or rights of way would be required to pipeline gas from the well to the proposed plant and then to a NOVA lateral. The Board is satisfied that APL can grant the necessary rights of way to Chinook in exchange for the existing easements. The Board notes that an application has not yet been filed for the NOVA pipeline lateral to deliver the gas to market. In view of the conflict beyond 1991 with Luscar's mining plans, approval is not certain.

9 DECISION

Having considered the evidence, the Energy Resources Conservation Board is prepared to grant the application of Manalta Coal Ltd. for a replacement licence to continue mining in accordance with the "Base Case" plan at the Vesta Mine (Mine No. 1046/01) in township 40, ranges 15 and 16, west of the 4th meridian. The licence would be subject to the following conditions:

1) Manalta shall submit for the approval of the Board a stability analysis and a code of practice for mining within 100 metres of the wellbore of the well, CHINOOK-RED WILLOW 6-13-40-16.

2) No mining shall take place within 100 metres of the wellbore of the well without obtaining the written approval of the Board.

3) One year prior to the planned land clearing and mining operations reaching the CHINOOK-RED WILLOW 6-13-40-16 well site, the Licensee shall submit its detailed mine plan schedule for the approval of the Board.

4) The proposed mine plan schedule shall have regard for the current status of both coal and gas operations in the area and shall allow recovery of both coal and gas resources in the most orderly, efficient, and economic manner.

5) Subject to Chinook completing construction of a pipeline to transport raw gas from the well, CHINOOK-RED WILLOW 6-13-40-16, to a gas processing facility not in the southwest quarter of section 13, Manalta shall pay 50 per cent of the costs of constructing the pipeline, but if the length or cost of the pipeline is deemed by Manalta to be excessive, it may appeal to the Board for reduction in the amount it is required to pay, and the written decision of the Board shall be final.

The orders to be issued would be of the form set out in the Appendix of this report, and would be subject to the terms and conditions contained therein, as well as to such other conditions as the Minister of the Environment may impose with respect to environmental aspects.

DATED at Calgary, Alberta, on 1 August 1985.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Board Member

C. J. Goodman, P.Eng.
Board Member

H. J. Webber, P.Eng.
Acting Board Member

APPENDIX

FORM OF LICENCE*

THE PROVINCE OF ALBERTA

COAL CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a surface coal
mine of Manalta Coal Ltd.
in the Cordel area

LICENCE NO.

WHEREAS Manalta Coal Ltd. is the holder of Permit No. C 76-63 authorizing development of a surface mine in the Cordel area; and

WHEREAS the Energy Resources Conservation Board convened a public hearing to consider Manalta Coal Ltd. Application No. 850327, registered on 29 March 1985 for replacement of mine Licence No. C 84-18; and

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Manalta Coal Ltd. for a licence to operate a mine within the permit area, subject to the conditions herein contained, and the Minister of the Environment has given his approval, hereto attached, insofar as the application affects matters of the environment.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Coal Conservation Act, being chapter C-14 of the Revised Statutes of Alberta, 1980, hereby grants to Manalta Coal Ltd. (hereinafter called "the Licensee") a LICENCE to operate a surface mine, subject to the provisions of the Act and regulations and orders pursuant thereto and to the following terms and conditions:

1. The mine shall be designated as Mine No. 1046/01.

2. This licence shall apply to some 1340 hectares, more or less, in Township 40, Ranges 15 and 16, West of the 4th Meridian, as shown in Appendix A hereto attached.

3. Subject to other provisions of this licence, all mining and related operations shall be in accordance with the application of the Licensee to the Energy Resources Conservation Board, registered as Application No. 850327 on 29 March 1985.

4. The Licensee shall follow the "Base Case" plan as outlined in the application and advise the Board of any significant modifications to the mining plan and obtain its approval therefor prior to effecting such modifications.

5. (1) The Licensee shall submit for the approval of the Board a stability analysis and a code of practice for mining within 100 metres of the wellbore of the well, CHINOOK-RED WILLOW 6-13-40-16.

(2) No mining shall take place within 100 metres of the wellbore of the well without obtaining the written approval of the Board.

* This is only a form of licence. The licence, when issued, may have minor variations from that set out here.

6. (1) One year prior to the planned land clearing and mining operations reaching the CHINOOK-RED WILLOW 6-13-40-16 well site, the Licensee shall submit its detailed mine plan schedule for the approval of the Board.

(2) The proposed mine plan schedule shall be based on the current status of both coal and gas operations in the area and shall allow recovery of both coal and gas resources in the most orderly, efficient and economic manner.

7. Subject to Chinook completing construction of a pipeline to transport raw gas from the well, CHINOOK-RED WILLOW 6-13-40-16, to a gas processing facility not in the southwest quarter of section 13, Manalta shall pay 50 per cent of the costs of constructing the pipeline, but if the length or cost of the pipeline is deemed by Manalta to be excessive, it may appeal to the Board for a reduction in the amount it is required to pay, and the written decision of the Board shall be final.

8. (1) The Licensee shall

(a) selectively mine all oxidized or inferior coal as may be directed by the Board, and

(b) market, store or dispose of such coal to the satisfaction of the Board.

(2) Any discard coal shall be disposed of in a manner satisfactory to the Board to prevent it from becoming a safety hazard or contributing to air or water pollution.

9. The Licensee shall implement effective dust-suppression programs to

(a) maintain a safe working environment,

(b) minimize coal losses, and

(c) minimize environmental degradation.

10. (1) Insofar as it affects matters of the environment, the application is subject to the approval of the Minister of the Environment.

(2) The approval of the Minister of the Environment, in accordance with subclause (1), is attached hereto as Appendix B, and this licence is subject to the terms and conditions therein contained.

11. (1) This licence shall expire five years from the date hereof.

(2) Notwithstanding subclause (1), where the Licensee demonstrates to the satisfaction of the Board and the Department of the Environment that mining and reclamation practices throughout the licence period have been acceptable, the Board may extend the term hereof for such further period or periods, not exceeding five years each, as it considers appropriate in the circumstances.

12. The Board may at any time

(a) cancel or suspend this licence, in whole or in part, for failure of the Licensee to comply with any provisions of the Act, the regulations or the terms and conditions set out herein; or

(b) amend this licence or make such other order as it thinks appropriate under the circumstances.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

(Chairman) (Vice Chairman) (Board Member)

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

APPLICATION FOR GAS REMOVAL PERMITS NORTHRIDGE PETROLEUM MARKETING, INC. SIGNALTA RESOURCES LIMITED TRICENTROL OILS LIMITED

Decision D 85-35
GR 85-1
Applications 850610
850611
850612

1 APPLICATIONS

Northridge Petroleum Marketing, Inc. (Northridge) applied to the Energy Resources Conservation Board (the Board), pursuant to section 2 of the Gas Resources Preservation Act (the Act), for three permits authorizing the removal of gas from Alberta. Northridge proposed that separate permits be issued to itself, Tricentrol Oils Limited (Tricentrol), and Signalta Resources Limited (Signalta), for the purpose of supplying gas to N-ReN Corporation (N-ReN) of Ohio, U.S.A., for use in the manufacture of ammonia at East Dubuque, Illinois, U.S.A. The permits would, in aggregate,

- provide for the removal of 415.6 million cubic metres (10^6 m^3) of gas in total,
- provide for the maximum annual removal of 310.8 x 10^6 m^3 of gas, and
- provide for the maximum daily removal of 993.5 thousand m^3 of gas.

The permits would also

- provide, in each case, for a term commencing with the approval of the Minister of Energy and Natural Resources and ending 1 November 1986, and
- name certain fields, pools, and areas from which gas may be obtained for removal from the province.

The Northridge permit would authorize the removal of 277 x 10^6 m^3 of gas in total; the Tricentrol and Signalta permits would each authorize the removal of 69.3 x 10^6 m^3 of gas.

The applied-for gas volumes would originate from lands in Alberta in which the applicants control the gas together with other working interest owners. Northridge has stated that it would purchase its own commitments to N-ReN from Lac Minerals Ltd. (Lac), Paloma Petroleum Ltd. (Paloma), Paramount Resources Ltd. (Paramount), and Wainoco Oil and Gas Limited (Wainoco). The gas would be transported in Alberta by NOVA, AN ALBERTA CORPORATION (NOVA) to Empress and by TransCanada PipeLines Limited (TransCanada) to a point of export near Emerson, Manitoba.

2 NOTICE OF FILING AND HEARING

A "Notice of Filing" respecting the applications was published in Alberta's major newspapers on 9 July 1985. Submissions were received from Canterra Energy Ltd. (Canterra), PanCanadian Petroleum Limited (PanCanadian), ProGas Limited (ProGas), and TransCanada. The Board conducted a public hearing of the applications in Calgary, Alberta, on 24 July 1985, with V. Millard, V. E. Bohme, P.Eng., and E. R. Brushett, P.Eng., sitting. The hearing was reopened on 19 August 1985 for the purpose of obtaining additional information on possible adverse impact of the proposal on other Alberta gas producers. The hearing participants are listed in the following table.

3 ISSUES

Section 5(3) of the Act provides that the Board shall not grant a permit for removal of gas from the province unless it is in the public interest of Alberta, having regard to, among other considerations

- the present and future needs of persons in Alberta,
- the established reserves and the trends in growth and discovery of reserves of gas or propane in Alberta, and
- the expected economic costs and benefits to Alberta of removal of the gas or propane from Alberta.

The Board has concluded that the main issue in the subject application is

- whether or not the economic costs and benefits of the proposed removal would be in the public interest of Alberta.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Northridge Petroleum Marketing Ltd. (Northridge) A. S. Hollingworth	R. M. Shillington D. G. Snyder G. L. Polley
Signalta Resources Limited (Signalta) A. S. Hollingworth	H. M. Sorensen
Tricentrol Oils Limited (Tricentrol) A. S. Hollingworth	Y. L. Mah
ProGas Limited (ProGas) D. G. Hart, Q.C.	V. L. Horte R. L. Harrop
PanCanadian Petroleum Limited (PanCanadian) D. G. Hart, Q.C.	W. C. Reinwart
TransCanada PipeLines Limited (TransCanada) E.W.H. Mallabone	
Independent Petroleum Association of Canada (IPAC) J. A. Snider	R. G. DeWolf
Energy Resources Conservation Board staff M. J. Bruni T. Walden G. A. Habib M. E. Mumby	

The Board has also concluded that, in the subject application, satisfactory resolution of the following matters is important to its decision on the main issue:

- Would the proposed sale to N-ReN represent an incremental market for Alberta gas?
- Would approval of the application have any impact on decisions of the U.S.A. Federal Energy Regulatory Commission (FERC) regarding its recent "Notice of Proposed Rulemaking"?
- Would approval of the application have any adverse impacts on the renegotiation of "firm-gas" contracts between Canadian shippers and U.S.A. buyers, and what would the magnitude of any adverse impacts be?

4 VIEWS OF THE APPLICANTS

The applicants stated that the applied-for volumes are available to them for removal, are surplus to Alberta's needs, and that the proposed gas sales would be incremental and in the public interest of Alberta. The applicants also stated that "short-term/best-effort" and "long-term/firm" gas sales represent two distinct markets, and that the long-term/firm sales of Canadian gas will not be influenced by short-term/best-effort sales. They argued that if "firm" gas obtains a lower price in current negotiations it would be the result of normal market pressures.

The applicants suggest that approval of their applications would have little or no effect on the FERC decisions regarding natural gas marketing in the U.S.A.

5 VIEWS OF THE INTERVENERS

5.1 ProGas

ProGas submitted that approval of the applications could affect the FERC decision on whether or not to permit the pass-through of demand charges associated with Canadian firm-gas exports. ProGas submitted that FERC could ignore arguments put forward by Canadian gas exporters, producers, producer associations, and governmental authorities to preserve the pass-through of demand charges, if Canadian regulatory authorities authorize spot exports at prices below the price of firm-gas sales.

ProGas expressed concern that lower spot-market prices could influence current renegotiation of prices in existing contracts for firm long-term exports.

5.2 PanCanadian

PanCanadian expressed the view that approval of the application, at spot-market prices lower than those being realized for firm gas, could affect price negotiations of firm-gas contracts in both eastern Canada and the U.S.A. PanCanadian recommended that the Board defer its decision on the applications until price negotiations on long-term/firm-gas contracts for the 1985/86 year have been completed.

5.3 TransCanada

TransCanada did not take a position on the application; however, it asked the Board to satisfy itself that the gas proposed to be removed from Alberta will serve a truly incremental market for Alberta gas.

5.4 IPAC

IPAC submitted that two distinct markets for natural gas exist in the U.S.A., one a short-term/best-efforts or interruptible market, and the other a long-term/firm-sales market. IPAC stated that it did not support the view that long-term/firm sales of Canadian gas would be significantly or unduly influenced by short-term/best-effort sales, and that if lower prices result from upcoming contract renegotiations it will likely be the result of an overall downward trend in energy prices.

6 VIEWS OF THE BOARD

Having regard for existing permit commitments, Alberta's present and future needs for gas, and the established and expected future reserves of Alberta gas, the Board agrees with the applicants that the small volume of gas proposed to be removed is surplus to Alberta's requirements.

The Board is satisfied that the proposed sale to N-ReN represents a substantially new market for Alberta gas and would therefore result in an increase in total sales of Alberta gas. The Board is also satisfied that the proposed sale of gas would be priced competitively with respect to competing fuels; however, in order to ensure that reasonable net benefits would accrue to Alberta as a result of the proposed sale, the Board would include appropriate conditions in any permits which may be issued to the applicants.

On consideration of the evidence regarding possible adverse impacts on other Alberta gas producers of approving the subject applications at this time, the Board believes that neither the FERC decision on proposed changes affecting gas marketing in the United States, nor the renegotiation of long-term/firm-gas sales contracts between Canadian shippers and United States buyers, would be substantially affected by approval of the applications.

7 DECISIONS

In light of its findings and responsibilities under the Act, the Board, with the approval of the Minister of Energy and Natural Resources, is prepared to grant gas removal permits to Northridge, Tricentrol, and Signalta, as requested in the subject applications. The permits would be in the form shown in Appendix A and would be subject to the terms and conditions contained therein, as well as any conditions imposed by the Minister of Energy and Natural Resources.

DATED at Calgary, Alberta, on 8 November 1985.

ENERGY RESOURCES CONSERVATION BOARD

V. Millard

V. E. Bohme, P.Eng.

E. R. Brushett, P.Eng.

APPENDIX
FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Northridge Petroleum Marketing Inc. authorizing the removal of gas from the Province

PERMIT NO. NM 85-3

WHEREAS Northridge Petroleum Marketing, Inc. has applied in Application No. 850610 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Northridge Petroleum Marketing, Inc. is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Northridge Petroleum Marketing, Inc. (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

   (a) during the term of the permit, a total of 277 000 000 cubic metres, nor

   (b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 622 300 cubic metres and in a 12-month period such rates shall not exceed 207 200 000 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Berry	Ghost Pine	Saleski
Caroline	Leahurst	Stanmore
Cessford	Leo	Sunnynook
Chain	Liege	Therien
Chard	Maple Glen	Valhalla
Edson	McLeod	Viking-Kinsella.
Gadsby	Princess	

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipelines of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this day of 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

APPENDIX
FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Signalta Resources Limited authorizing the removal of gas from the Province

PERMIT NO. SR 85-2

WHEREAS Signalta Resources Limited has applied in Application No. 850612 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Signalta Resources Limited is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Signalta Resources Limited (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

(a) during the term of the permit, a total of 69 300 000 cubic metres, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 165 600 cubic metres and in a 12-month period such rates shall not exceed 51 800 000 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Beaverhill Lake	Killam	Sedgewick
Birch	Killam North	Strome
Bruce	Mannville	Ukalta
Donalda	Medicine River	Viking-Kinsella
Forestburg	Norris	Warwick
Hairy Hill	Plain	Wavy Lake
Inland	Ranfurly	Whitford
Jarrow	Royal	Willingdon.

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipeline of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contracts which specify the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this day of 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

APPENDIX
FORM OF PERMIT*

IN THE MATTER of the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984; and

IN THE MATTER of a permit to Tricentrol Oils Limited authorizing the removal of gas from the Province

PERMIT NO. TO 85-3

WHEREAS Tricentrol Oils Limited has applied in Application No. 850611 to the Energy Resources Conservation Board for a permit, pursuant to the Gas Resources Preservation Act, authorizing the removal from the Province of gas produced from certain pools, fields and areas; and

WHEREAS the Board, upon inquiry into the application, has found that Tricentrol Oils Limited is a person who appears to have made arrangements to purchase gas within the Province and proposes to remove such gas from the Province, and that the provisions of the Gas Resources Preservation Act affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of the application for the removal of gas from the Province is in the public interest, having regard to the present and future needs of persons within the Province, to the established reserves and trends in growth and discovery of reserves of gas in the Province, and to the expected economic costs and benefits to Alberta of the removal of the gas from the Province; and

WHEREAS the Minister of Energy and Natural Resources has given his approval, hereto attached as Appendix A.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Gas Resources Preservation Act, being chapter G-3.1 of the Statutes of Alberta, 1984, hereby grants a permit to Tricentrol Oils Limited (hereinafter called "the Permittee") authorizing the removal of gas from the Province, subject to the regulations and orders made pursuant to the said Act and the terms and conditions prescribed in this permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be operative for a 2-year term commencing on the date hereof.

2. The quantity of gas that may be removed from the Province pursuant to this permit shall not exceed,

   (a) during the term of the permit, a total of 69 300 000 cubic metres, nor

   (b) during any consecutive 24-hour period or any consecutive 12-month period ending 31 October, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 165 600 cubic metres and in a 12-month period such rates shall not exceed 51 800 000 cubic metres.

3. Notwithstanding clause 2, subclause (b) the Permittee, for purposes only of alleviating temporary operating problems caused by pipeline or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized for such period by clause 2, subclause (b).

* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

4. (1) The Permittee, subject to clause 5, may remove or cause to be removed from the Province under the authority of this permit, only gas produced from the following pools, fields and areas:

Bentley	Gold Creek
Ferrier	Pouce Coupe.

(2) Each pool, field or area named in clause 4, subclause (1) of this permit shall be construed as being the pool, field or area of the same name, as such pool, field or area may be designated from time to time by the Board, pursuant to the Oil and Gas Conservation Act.

(3) Where any pool, field or area named in this permit is revised or designated by the Board in a manner otherwise than by the name referred to herein, the Board may, by stipulation hereto, substitute the revised name designated for any such pool, field or area named in this permit.

5. (1) For purposes of this permit, gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) may, subject to the provisions of subclauses (2) and (3), be removed from the Province in substitution for gas produced or to be produced from pools, fields and areas named in clause 4, subclause (1).

(2) The total volume of gas removed from the Province during each 12-month period ending 31 October shall not exceed the total volume of gas actually produced from the pools, fields and areas named in clause 4, subclause (1).

(3) Gas acquired by the Permittee from sources other than from pools, fields and areas named in clause 4, subclause (1) shall be deemed to be first used to supply sales to consumers, communities and utilities in Alberta, pipeline fuel and losses, and fuel and shrinkage at reprocessing plants in Alberta.

(4) For the purpose of this clause, all volumes shall be balanced on an energy basis.

6. The Permittee shall remove or cause to be removed pursuant to this permit only such gas as is transported on behalf of the Permittee through Section 11 or Section 12, both in Township 20, Range 1, West of the 4th Meridian, for delivery from the facilities of NOVA, AN ALBERTA CORPORATION to the pipeline of TransCanada PipeLines Limited.

7. (1) All gas removed from the Province pursuant to this permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located so as to measure the gas which is delivered in accordance with the approved points of removal referred to in clause 6.

(2) The relative density and higher heating value of all gas received by the Permittee through the facilities referred to in clause 6 shall be measured by or on behalf of the Permittee at or near the points at which gas is delivered by the said facilities.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this permit.

9. The Permittee shall,

(a) before removal of gas from the Province, file copies of the Gas Sales Contract which specifies the price to be paid for the gas at the Canadian border, and

(b) upon the execution thereof, promptly file copies of any documents which change the price to be paid for gas.

10. The Permittee shall satisfy the Board throughout the term of the permit that the price to be paid for gas continues to be in the public interest of Alberta within the meaning of section 5(3) of the Act.

11. All quantities of gas for the purpose of this permit shall be referred to a 101.325 kilopascal pressure base and a 15° Celsius temperature base.

12. The Permittee shall supply gas from the pipeline of NOVA, AN ALBERTA CORPORATION at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas from such community or consumer that is willing to take delivery of gas at a point on the pipeline transmitting the gas, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

13. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 12 and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

14. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this day of 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

MURPHY OIL COMPANY LTD.
COMMERCIAL OIL SANDS PROJECT (PHASE 1)
LINDBERGH SECTOR

Decision D 85-36
Application 841338

1 INTRODUCTION

1.1 The Application

Murphy Oil Company Ltd. (Murphy) applied pursuant to section 10 of the Oil Sands Conservation Act for approval in principle of a commercial oil sands project (the Lindbergh Thermal Recovery Project) and for approval to construct and operate Phase 1 of the project. The proposed development would recover crude bitumen resources from the Cold Lake Oil Sands Deposits using a cyclic steam stimulation recovery technique. Murphy currently operates an experimental oil sands project in section 13, township 58, range 5, west of the 4th meridian, under Energy Resources Conservation Board Approval No. 1954. The Lindbergh Thermal Recovery Project would be a commercial expansion of Murphy's experimental project.

The Lindbergh Thermal Recovery Project would be developed in four separate phases initiated over a period of 9 years and ultimately resulting in a total project operating life of 31 years. The implementation and timing of any phase subsequent to Phase 1 would, however, be contingent on a technical and economic evaluation of the preceding phase(s) and on the results of production tests at the location of the phase under consideration. Each phase would be designed to achieve a productivity of 400 cubic metres per day (m^3/d) of bitumen for an ultimate project production goal of 1600 m^3/d. Phase 1 of the project would be located on four sections as shown on Figure 1, with subsequent phases to be developed on other Murphy leases in the area (Figure 2).

Phase 1 of the project would initially require the drilling of 53 wells. Thereafter, an average of 18 wells would be drilled each year in order to maintain the desired level of productivity (400 m^3/d) for the 20-year life of the phase. All wells would be drilled directionally from 9-well central pad locations. Also included in Phase 1 would be the construction of central processing and storage facilities, steam generation facilities, pad facilities, and pipelines.

1.2 Interventions

Interventions expressing concerns or opposition to Murphy's application were filed by Mr. A. Opanavicius, registered owner of sections 11 and the southwest quarter of 14 and lessee of the northwest quarter of 14, all in township 58, range 5, west of the 4th meridian; the Elk Point Surface Rights Association (EPSRA); and the Elizabeth Metis Settlement Association No. 9 and the Federation of Metis Settlements (the Settlements).

Interventions in support of the application were filed by the Town of Elk Point and Dome Petroleum Ltd. Alberta Municipal Affairs filed a submission pursuant to section 26 of the Board's Rules of Practice indicating it had no objection in principle to Murphy's application but was concerned that if the project proceeded to the lands of the Elizabeth Metis Settlement No. 9, social impacts of the project would have to be further explored.

1.3 The Hearing

A public hearing was held on 18 June 1985 and 3, 4, and 5 July 1985 before Board members G. J. DeSorcy, P.Eng., L. A. Bellows, P.Eng., and N. A. Strom, P.Eng. A view of the proposed project site that would occupy Mr. Opanavicius' lands was taken by the Board and representatives of the applicant and interveners on the afternoon of 4 July 1985. Those who appeared at the hearing are shown in Table 1.

2 PRELIMINARY MATTERS

2.1 Adjournment

Application was made at the opening of the hearing for an adjournment of the proceeding. That application, made by Mr. Opanavicius, was supported by EPSRA and by the Settlements. Mr. Opanavicius argued that the amount of notice he had received of the hearing was not sufficient to allow him time to assess the impact the proposed facility could have on his land and to adequately prepare for the hearing. He further argued that an adjournment of the proceeding would allow him and those persons assisting him the oppor-

tunity to have further discussion with the applicant, and possibly a senior Energy Resources Conservation Board staff person, to better define the issues.

Although the Board determined that reasonable notice had been provided to Mr. Opanavicius, it concluded that it would be in the interest of a more efficient completion of the proceeding to grant a 2-week adjournment. The Board further advised that a senior Board staff person that was not a participant in the processing of the application or the hearing would be made available to assist in any land use discussions, if so requested by both parties.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	**Witnesses**
Murphy Oil Company Ltd. (Murphy) A. L. McClarty	R. T. McLean, P.Eng. L. H. Bland, P.Eng. A. Griffin, P.Eng. P. Ullman, P.Eng.
Mr. A. Opanavicius B. K. O'Ferrall	A. Opanavicius R. Berrien R. Danyluk
Elk Point Surface Rights Association (EPSRA) P. T. Johnson	A. Bugej R. Danyluk
Elizabeth Metis Settlement Association No. 9 and Federation of Metis Settlements (the Settlements) D. Sevalrud E. Soloway	J. Foster J. Courtepatte
Town of Elk Point S. P. Vincent	
Dome Petroleum Limited A. R. Fraser R. K. Dixon, P.Eng.	
Alberta Municipal Affairs B. Miller H. Lett	
Alberta Environment Development and Reclamation Review Committee L. Brocke	
Energy Resources Conservation Board staff H. R. Hansford K. Sadler, P.Eng. T. Abel, E.I.T. R. Feick	

2.2 Preliminary Applications by the Settlements

The Board was asked by Murphy to issue approval for Phase 1 of a four-phase project and to give an approval in principle for Phases 2, 3, and 4, one of which would be entirely within Metis Settlement lands. The Settlements made two separate but related preliminary applications.

Initially, the Settlements requested that the proceeding be adjourned to allow them the opportunity to assess the impact the proposed project may have on them. Recognizing that Phase 1 of the project would not impact on them, they maintained that if approval in principle for the entire four-phase project was to be considered, there was not sufficient information

submitted to allow them to determine whether the overall development proposal would have an impact.

The Settlements requested in the alternative that the Board amend the Murphy application by order, pursuant to Rule 30 of the Board's Rules of Practice. This amendment would be to preclude consideration of approval in principle of the four-phase project and would restrict consideration to Phase 1, to which the Settlements were not opposed.

Murphy argued that its application was only for approval of Phase 1 of a four-phase project and that approval in principle of the other three phases was merely a request to the Board to assess the initial phase in the context of the overall potential development and to advise whether there is any reason why Murphy should not pursue its long-range plans.

The Board determined that because the legislation makes no provision for approval in principle, it was not prepared to consider such an approval for Phases 2, 3, and 4. Therefore, the request to direct Murphy to amend its application, albeit unnecessary, was denied. However, the Board commented that Murphy's inclusion of information in its application respecting three possible future phases is consistent with a number of requests from the people in the area for information respecting possible future developments. The Board also denied the Settlements' application for adjournment on the basis that the proposed Phase 1 would not involve the Settlements' land and therefore an adjournment to assess the impact on those lands was unnecessary.

3 ISSUES

During the course of the hearing, a number of matters were raised that were of particular concern. Those issues that the Board believes to be of significance can be categorized as follows:

- pad size and design
- size of transportation/utilities right of way
- overhead electric power distribution
- drilling mud disposal
- reclamation
- general concerns

The category of general concerns includes a number of varied issues which, although important, received considerably less attention at the hearing. Those issues include:

- technical design and expected recovery
- fresh water requirements
- impacts on air quality
- facilities orientation
- land fill sites
- social and economic impacts
- information sharing
- enforcement of regulations and project conditions

4 PAD SIZE AND DESIGN

Murphy stated it would require a 1.6-hectare (ha) lease for the well pads during drilling and construction, but only a 0.4-ha lease once project operations commenced. Murphy explained that the lease sizing was based on experience gained from its experimental operations. The applicant compared the proposed well pads to conventional single well leases of the same size, stating that the pad configuration actually provided more working space because the wellheads would be positioned to one side of the lease rather than being centrally located. In summary, Murphy stated it was confident that the pad design provided for all possible operational activities and conditions, but further indicated that if it were determined, by experience, that the operating leases were too small, it would be prepared to adopt a larger size by returning less of the original construction lease.

Mr. Opanavicius and EPSRA were concerned that Murphy's proposed pad size was too small and that the design of the pad had not properly considered all possible operational situations and conditions. They believed that the pad size was insufficient to accommodate such operations as multiple well servicing and snow removal and storage. Mr. Opanavicius believed that the small pads would inevitably result in frequent and disruptive trespass.

The Board is generally satisfied with Murphy's proposal for the construction and drilling phase of the project and accepts the proposed 0.4-ha operations lease. The Board, however, shares the concern that Murphy may not be able to carry out normal project operations on a 9-well pad of that size and would require Murphy to adopt a larger size operations lease if necessary.

5 SIZE OF TRANSPORTATION/UTILITIES RIGHT OF WAY

Murphy requested endorsement of a single right of way (r.o.w.) within which it would locate and maintain the roads, ditches, pipelines, and powerlines associated with the project. It further explained that the r.o.w. was designed to accommodate all construction activities as well as the storage of topsoil. Murphy recognized

that the specific r.o.w. width would be dependent on terrain, but stated it would require an average of 35 metres (m) and provided details to substantiate that requirement. Murphy believes that the proposed r.o.w. design is the most appropriate compromise of its needs and the minimization of surface disturbance. While some of r.o.w. would be reclaimed, it was Murphy's intent to keep the lease for the entire 35 m in order to provide access to maintain pipelines and powerlines.

Mr. Opanavicius was concerned that Murphy was requesting a r.o.w. that was too small to accommodate all the proposed uses. He was particularly concerned that there would be insufficient space for the pipeline installations.

The Board has reviewed the needs and requirements presented by Murphy and accepts the 35-m proposal. It is understood that minor variations to this r.o.w. requirement may be necessary to accommodate specific terrain conditions.

6 OVERHEAD ELECTRICAL POWER DISTRIBUTION

Murphy stated that it would be using overhead powerlines for its electrical distribution system. It explained that overhead lines were chosen in preference to an underground system primarily for reasons of cost but also because the overhead system provides greater ease of maintenance. Murphy submitted cost estimates and comparisons for the two alternatives which indicated that underground power would be \$60 000 more per kilometre of utility corridor. The most significant part of the additional expense of underground power was for the transformers. In response to a suggestion by the interveners, Murphy stated that it would not use underground lines with overhead transformers because technical and safety problems had occurred elsewhere with that arrangement.

Murphy did not believe that the overhead lines would preclude aerial spraying of crops. It believed that the one-third of a mile separation between the utility corridors would provide linear corridors of adequate width for spraying. If necessary, however, it believed helicopter spraying would be an appropriate alternative.

Mr. Opanavicius had two concerns regarding the use of overhead powerlines and as such would prefer Murphy to use underground lines. He was concerned with the danger associated with accidental contact and that overhead lines would greatly inhibit the aerial spraying of his crops. While he recognized that it would be possible to spray portions of his fields, he noted that effective and complete coverage would not be possible and in some cases, such would be imperative. Mr. Opanavicius believed that Murphy had not fully evaluated the potential losses he could suffer associated with this problem and further believed his potential losses merited greater consideration when evaluating the two power distribution alternatives.

It is evident that the project will have a marked impact on land use in order to accommodate the array of facilities required for this kind of operation. Having regard for other farming disruptions inherent to the project including flare stacks, steam generator stacks, wells, and roads, the Board considers overhead powerlines a rather limited additional impact on farming operations. The Board therefore accepts Murphy's proposal to install overhead lines, but would expect Murphy to explore the use of buried lines with the landowner when the need is especially important to the farming operation. In making this determination, the Board assumes that any incremental impacts resulting from overhead lines would be reflected in compensation paid to the landowner.

7 DRILLING MUD DISPOSAL

Murphy stated that it would be drilling nine wells per drilling lease using a common sump to contain the drilling mud. When the drilling of the nine wells was completed, Murphy would "squeeze" the sump on the lease. Murphy explained that the sump squeezing procedure would involve mixing the sump contents (primarily drill cuttings and fresh-water based gel mud) with the subsoil, spreading the mixture on lease, and later replacing the topsoil. Murphy stated that the volume of drilling mud disposed in this manner would be equivalent to a depth of 3.6 centimetres (1.5 inches) spread evenly over a 1.2-ha area. Murphy recognized that there were alternate disposal methods available, but stated it chose on-lease disposal because it was a commonly used and accepted practice and was considerably less expensive than the alternatives. Further, Murphy did not believe that the squeezing procedure would or had ever been proven to adversely impact the agricultural productivity of the land.

Mr. Opanavicius expressed concern regarding the effect of drilling mud disposal on agricultural lands. Because the applicant could not definitively predict the effect the squeezing procedure would have, Mr. Opanavicius stated he would prefer the sump materials were disposed of in an alternative way. He recognized Murphy's

proposal to mix the material with the subsoil, but indicated that the shallow nature and varying depth of the topsoil made accidental cultivation of the subsoil a distinct possibility. EPSRA echoed Mr. Opanavicius' concerns and stated they felt the disposition of sump materials should be a matter that requires mutual consent of the applicant and landowner.

The Board recognizes that while the effect of drilling mud on soil productivity varies with site-specific soil properties and mud properties, thousands of well sites throughout the province have been successfully reclaimed by the method Murphy proposes. The Board is reasonably confident that careful attention to the drilling mud disposal program with direct advice from the landowner and the reclamation experts will foster a successful reclamation. The Board concludes that the evidence respecting sump disposal does not warrant requiring an alternative disposal method.

8 RECLAMATION

Murphy stated that it had not submitted a Development and Reclamation (D&R) application to the Land Conservation and Reclamation Council prior to the hearing, but did have a preliminary draft completed. It stated that the D&R application had been delayed in order to address and incorporate any issues arising from the hearing that might impact on its D&R plans. Murphy indicated that it would be willing to accept input from landowners regarding the plan and was willing to provide them with a copy of the completed D&R application.

In addressing some specific issues raised, Murphy stated it intended to return the soils in reclaimed areas to a state at least equivalent to surrounding soils. It explained that the procedures used would be governed by its soil sampling program and could include the addition of fertilizers. Murphy also explained that soil stripping criteria would be dictated by the studies done for the D&R application and the actual stripping would be monitored closely to ensure compliance with the D&R approval.

The interveners were particularly concerned that the project would proceed without properly addressing the development and reclamation aspects. They believed that the Board could not consider Murphy's application complete until a D&R plan was in place. Of particular importance to the interveners was soil stripping, soil degradation due to storing practices, and the enforcement of D&R approval conditions and commitments.

Mr. L. Brocke of the Development and Reclamation Review Committee described the manner in which the D&R application would be considered. He also commented on the matter of public input to the process.

The Board notes that it does not have direct jurisdiction in the area of reclamation but in any case would want to be satisfied the project development is proceeding in a manner that would ensure effective reclamation is possible. The Board is satisfied, on the basis of its visit to the Opanavicius lands and Murphy's evidence, that successful reclamation will be possible provided particular care is taken when stripping and storing topsoil. These practices are subject to scrutiny by the local Development and Reclamation Officer and the concerned landowner. If the project is approved and Murphy proceeds with it, the Board will also ask its field staff to watch that careful practices are used. If problems are noted, or if the Board receives complaints from the landowner, they will be pursued through direct contact with the Development and Reclamation Officer.

9 GENERAL CONCERNS

There were a number of matters raised at the hearing that were not of primary concern and as such were not addressed in significant detail, but the Board believes these matters merit brief comment.

The Board has reviewed, in detail, the various technical aspects of Murphy's project relating to the resource recovery. The Board is satisfied with the applicant's technical design and is prepared to recognize a 17 per cent recovery based on that design. The Board also notes Murphy's intent to experiment with follow-up recovery methods which could ultimately increase the total recovery and the life of the project.

Fresh water required for the project would be supplied to the facilities by a pipeline from the North Saskatchewan River. Withdrawal of water from the river is contingent on Alberta Environment approval, but the Board is generally satisfied that both the source and the method of transport are acceptable and effectively minimize any potential related impacts.

The interveners expressed concern regarding the emissions associated with the proposed project. The Board is satisfied that Murphy's design commitment to gather and subsequently burn all annulus gases would greatly reduce the impacts on air quality. The Board further notes that Murphy would be required to obtain and operate within the guidelines of the Alberta Environment Clean Air Act Licence.

Concern was also expressed by interveners with respect to the impact on cultivated or potentially cultivated land from the linear orientation and location of surface facilities. In an effort to resolve those concerns, the applicant and the interveners had agreed prior to the hearing that the details of Murphy's developments on section 11 and the west half of section 14 would be deferred until such time as the project expansion to those lands becomes more imminent. They also agreed that the orientation adopted would require the consent and agreement of the landowner, Mr. Opanavicius, and if agreement could not be reached, the matters at issue would be referred to the Board. The Board accepts this resolution respecting orientation and any approval issued by it would be conditioned accordingly.

The Town of Elk Point raised the issue of a need for the establishment and operation of a regional sanitary landfill site. The Board recognizes such a potential need and is satisfied that the recent formation of the Lakeland Sanitary Landfill Authority is an appropriate means of dealing with this issue.

EPSRA raised several issues related to the potential social and economic impacts associated with the project. Of particular concern were employment opportunities for rural residents and a perceived lack of attention given by Murphy to impacts on the rural community. The Board has serious reservations with the approach suggested by EPSRA concerning preferential treatment for rural area residents respecting employment opportunities and is satisfied with Murphy's statement that local area residents would be hired whenever practical. The Board is satisfied that all of the potential social and economic impacts have been adequately addressed by Murphy, and as such are acceptable.

During the course of the hearing it became apparent that much of the interveners' concerns were related to ineffective communication and information sharing. The Board is aware of this particular problem and has taken steps to address this issue. In this regard, the Board is currently exploring the establishment of an Information Centre in Elk Point.

Several references were made during the hearing, by the interveners, as to how commitments and decisions arising from the proceedings would be monitored and enforced. The Board through its staff takes an active role in following up and enforcing its decisions and approval conditions. This would include measures that range from routine field inspections to special actions involving liquid spills, and to monitoring on an annual basis the project operating performance. For special incidents, the operator and landowner are brought together to evaluate impacts and corrective measures and the Board staff advises both when it considers the problem to be resolved. The Board is prepared to discuss with any involved party, upon request, the status of follow-up activity respecting any specific item of this nature.

10 DECISION

The Board, having reviewed the evidence provided by the applicant and the interveners, is satisfied that the project is technically and environmentally sound and would result in substantial economic benefits to both the region and the province.

The Board is therefore prepared to approve Application 841338 by Murphy Oil Company Ltd. for Phase 1 of a commercial oil sands project in the Lindbergh Sector of the Cold Lake Oil Sands Area.

Subject to receipt of an Order in Council authorizing the granting of the approval and ministerial approvals from the Minister of the Environment and the Associate Minister of Public Lands and Wildlife, the Board will issue an approval with appropriate conditions.

DATED at Calgary, Alberta, on 19 August 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

L. A. Bellows, P.Eng.
Board Member

N. A. Strom, P.Eng.
Board Member

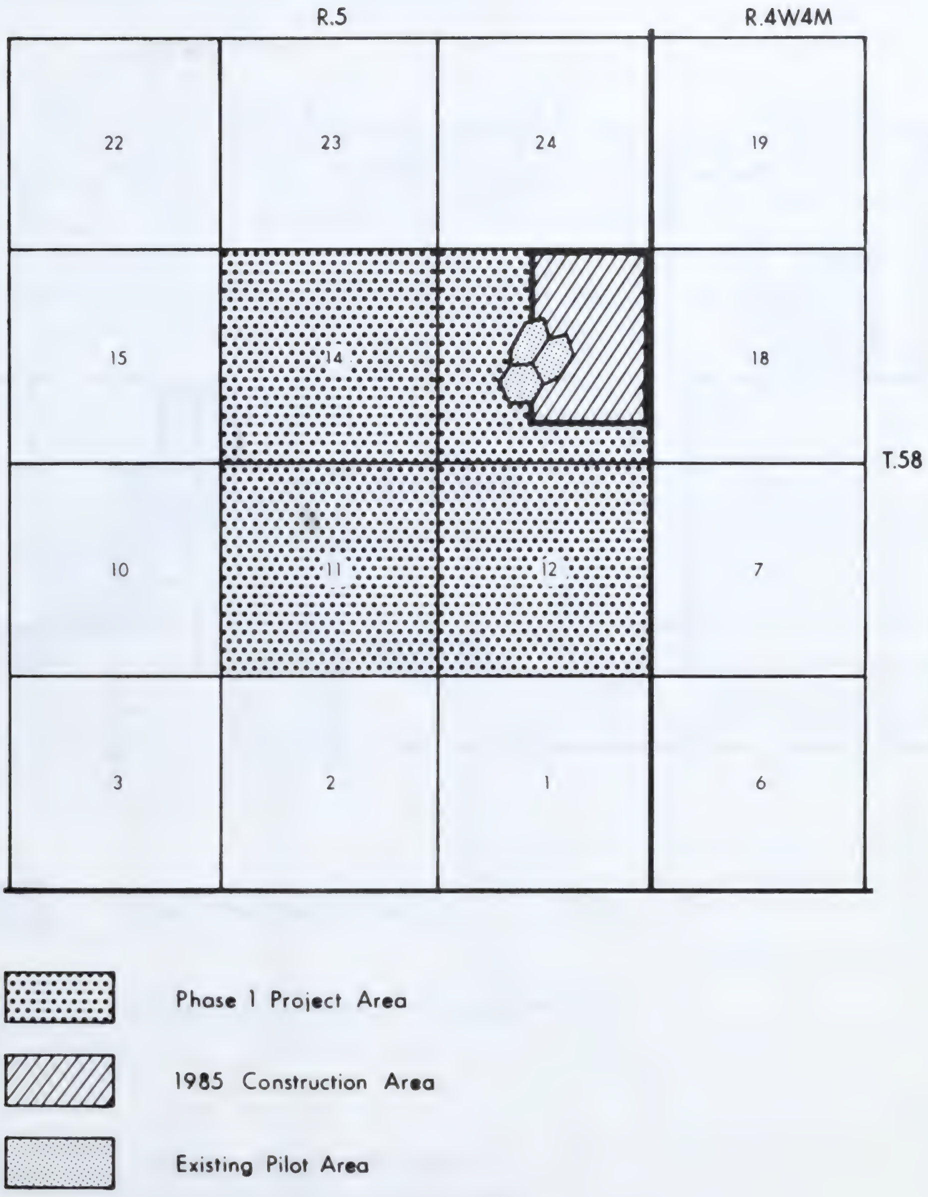


FIGURE 1 PHASE 1 DEVELOPMENT AREA
LINDBERGH SECTOR

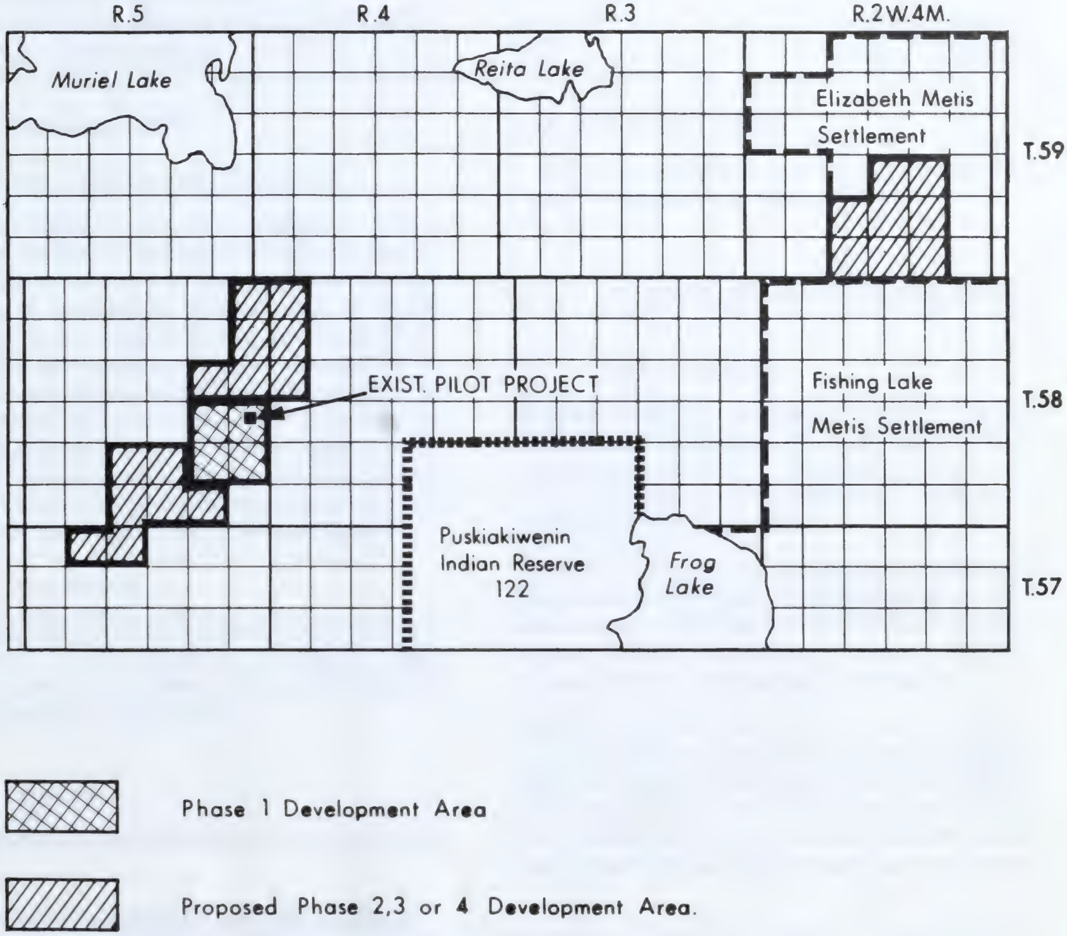


FIGURE 2 GENERAL LOCATION MAP
COLD LAKE OIL SANDS AREA

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

MAYNARD ENERGY INC. APPLICATION FOR A WELL LICENCE POUCE COUPE FIELD

Decision D 85-37
Application 850704

1 INTRODUCTION

1.1 The Application and Intervention

Maynard Energy Inc. applied pursuant to section 2.020 of the Oil and Gas Conservation Regulations for a well licence to drill a well in legal subdivision 6 of section 24, township 80, range 12, west of the 6th meridian (Lsd 6-24-80-12 W6), in the Pouce Coupe Field. The well would be drilled to evaluate and obtain production from the Charlie Lake (Charlie Lake) and the Halfway (Halfway) Formations. An intervention opposing the application was filed on behalf of Bryan and Cori Ellingson, the surface owners of all the west half of section 24-80-12 W6, except the parcel located in the northwest quadrant of Lsd 5 (see Figure 1).

1.2 The Hearing

A public hearing of the application was held on 8 August 1985 at the Golden Inn in Grande Prairie, Alberta, before V. E. Bohme, P.Eng., E. R. Brushett, P.Eng., and H. J. Webber, P.Eng.

2 ISSUES

The Board considers the issues related to the application to be:

- the need for the well; and
- the surface location of the well and access road, and the impact on farming operations.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Maynard

Maynard submitted that it had the right to drill for and produce the reserves underlying the southwest quarter of section 24-80-12 W6 (section 24) by virtue of a farm-out agreement with Mobil Oil Canada, Ltd. and Sulbath Exploration Ltd.

Maynard stated that the proposed well location was determined by geological interpretation, which suggested that the northwest quadrant of Lsd 6 was the optimum location to obtain a productive well in its primary objective, the Halfway (see Figure 2).

Maynard submitted that a porous reservoir referred to as a coquina bank trends in a northwest-southeast direction within the Halfway sand bar. It stated that the sucessful Halfway wells located at 6-34-80-12 W6 (6-34), 8-33-80-12 W6 (8-33), and 14-34-80-12 W6 (14-34) had penetrated this coquina bank and that, based

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Maynard Energy Inc. (Maynard) R. Smith P.Eng.	R. Smith, P.Eng. G. Moffat, P.Geol. L. Leblanc
Bryan and Cori Ellingson J. D. Carter	Bryan Ellingson (Mr. Ellingson)
Energy Resources Conservation Board staff A. A. Gervais C. Hill R. L. Paulson N. F. Lord	

upon its geological mapping, this porosity trend continues southeast to the proposed well location at 6-24 (see Figure 2).

The applicant contended that the abandoned well at 11-24-80-12 (11-24) contains 0.9 metres (3 feet) of potential hydrocarbon (by-passed) pay as indicated by a 3-foot porosity break on the sonic log. Maynard stated that the zone had a porosity of 16 per cent as determined from the sonic log, and that porosities in excess of 10 per cent usually were of interest as pay. It acknowledged that a drill stem test over the Halfway in the 11-24 well recovered 56 metres of mud and 304 metres of water, but suggested that if the zone had been acidized and fractured it could have been productive of hydrocarbons.

Maynard said that it believed that the 11-24 well is located on the northeast flank of the coquina bank as evidenced by its isopach map. It submitted that the porosity in the coquina bank drops off rapidly to the northeast. This was suggested by a decrease in net pay from 3.9 metres in the 6-34 well to zero in the 14-26 well. Maynard indicated that the crest of the reservoir would be located southwest of the 11-24 well and therefore, it contended that locating the proposed well in the northwest quadrant of Lsd 6, rather than in the primary target area in the northeast quadrant of Lsd 6, would maximize the potential pay encountered and consequently minimize risk. In addition, locating the well downdip of the 11-24 well should enhance the potential of encountering oil rather than gas.

In summation, Maynard submitted that, based on the available geological data, the proposed site is the best one for obtaining a productive well. Any movement of the well location in an easterly direction, as proposed by Mr. Ellingson, would greatly increase the risk of drilling an unsuccessful well.

With respect to the well's impact on farming operations, Maynard submitted that it had attempted to position the well site and access road so as to minimize any adverse impact. The well location lies along an existing crop line, thereby minimizing severance. Maynard was prepared to construct a low profile access road, where possible, to facilitate crossing with farm machinery. It also agreed to locate the road in the bush where this is possible, as suggested by Mr. Ellingson, to reduce the amount of crop land taken. If a productive well was obtained, Maynard would reduce the area of the well site required for permanent production, leaving the remaining portion of the lease available for cultivation. Maynard stated that any additional hindrance to farming operations, such as additional turning of farm equipment, could be compensated for pursuant to the Surface Rights Act. With respect to the alternative location suggested by Mr. Ellingson, Maynard did not believe there was any significant difference in impact, as compared to its preferred location, which could not be addressed by compensation.

Maynard stated that it did not believe that directional drilling was a viable alternative, given the increased costs involved and the risk of encountering additional drilling problems. Further, Maynard submitted that, to date, it had not drilled a directional well, had no experience with the technology and, therefore, would be reluctant to undertake such a proposal.

3.2 Views of the Ellingsons

Mr. Ellingson did not file any written evidence in support of his contention that the proposed well would interfere with his farming operations. He did not dispute the need for the well nor Maynard's right to attempt to recover any reserves which could underlie the drilling spacing unit.

Mr. Ellingson's counsel submitted that, on the basis of the applicant's response to questions, it was clear that the risk involved in obtaining a successful well in the northeast corner of Lsd 6, in the primary target area, was the same as that of the proposed location in the northwest corner of Lsd 6. He argued that Maynard's geological evidence was highly interpretive. He said that his client did not submit any geological evidence, as he believed the onus was on Maynard to substantiate, with definitive evidence, the need to move the well out of the primary target area.

Mr. Ellingson submitted that a well location in the northeast quadrant of Lsd 6, within the primary target area, would alleviate the concerns with respect to the proposed location. He contended that a well located in the primary target area would interfere far less with his farming operations than one in Maynard's preferred location, as fewer turns would be required when working the field with his farm implements. Further, Mr. Ellingson submitted that Maynard's present location and associated access road would sever his land, creating small areas in his field. Since he had cleared bush and was attempting to remove obstacles and increase his cultivated area, this severance was not desirable. Mr. Ellingson stated that even if an access road were constructed with a low profile, equipment would still be difficult to move over it and farming patterns would be interrupted by the road. With the well located in the primary target area, an access road could be run from the north along the east property line, thereby avoiding the severance of the field and any need to

cross over the road (see Figure 1). In addition, crop loss would be reduced because less cultivated land would have to be incorporated into the access road.

Mr. Ellingson said that the proposed access road borders a field containing a certified seed crop of brome and that the proposed road would likely increase weeds in his field. The presence of any quack grass would reduce the grade of seed and, consequently, its market value.

Mr. Ellingson did not agree with Maynard that the inconvenience and impacts created by a well situated in the northwest corner of Lsd 6 could be adequately compensated for over the life of the well. He said compensation was not an issue, because it was his desire to farm his lands in the most efficient and convenient pattern.

Mr. Ellingson requested that, should a well licence be issued, it address the matter of a power line to the well site. He asked that the operator be required to run electric power underground so as to cause the least impact on his operations, unless the operator could supply evidence to the Board to demonstrate that it is not viable.

3.3 Views of the Board

The Board accepts Maynard's right to recover the reserves which may underlie the southwest quarter of section 24, and therefore the need for a well.

The Board also accepts the applicant's view that the economic prospects of the proposed well are marginal and, therefore, it agrees that the costs and risks associated with directional drilling do not make it an acceptable alternative.

The Board accepts Mr. Ellingson's position that the proposed access road and well site would have a greater long-term impact on his farming operations than one located in the northeast corner of Lsd 6 with access from the north along the quarter section line. The Board also accepts that locating the well in the northeast corner of Lsd 6 in the primary target area would eliminate division of his fields and crossing of the access road with farm implements.

The Board agrees with Maynard that the depositional environment of the Halfway coquina bank characteristically results in narrow reservoirs trending in a northwest-southeast manner. With respect to the area of interest (see Figure 2), the Board believes that too few wells have penetrated the known oil pool (oil wells at 8-33 and 6-34) to establish the nature and limits of the pool, and thus the Board believes that the applicant's extrapolation of the known oil pool southeast to include the proposed well location is highly uncertain. The Board notes that the applicant indicated reservoir continuity may not exist between the two areas. The lack of proven reservoir development at the 14-26 well could indicate the end of the development of the northern pool. The Board agrees with the applicant that the northeastern extent of the reservoir is limited, as evidenced by absence of porosity development in wells at 11-17-80-11, 6-19-80-11, 6-25-80-12, and 14-26-80-12. The position of the southwest flank of the pool is, however, speculative.

The Board believes that the optimum location of the proposed 6-24 well must be influenced to a large extent by geological data obtained from the 11-24 well. The Board has reviewed the log data for the 11-24 well and concurs with Maynard regarding the potential for hydrocarbon pay in the Halfway. The Board notes, however, that a comparison of log characteristics with the productive 8-33 and 6-34 wells suggests considerably more net pay thickness in the 11-24 well than indicated by the applicant. Maynard had presented evidence that indicated porosities of 10 per cent or better were of interest. The Board notes that the 6-34 well has a maximum porosity of 9.5 per cent and an average porosity of 9 per cent (from sonic log, based on Maynard's calculation that 240 micro-seconds per metre equals 16 per cent porosity). The Board, therefore, believes Maynard's evaluation of potential net pay thickness in the 11-24 well is conservative, but agrees that any net pay attributable to the well is speculative, considering the nature of the drill stem test results.

The Board believes well control is insufficient to establish the limits of any Halfway reservoir in the vicinity of section 24-80-12. In addition, the Board believes that Maynard's interpretation that the pool terminates in section 24-80-12 and, therefore, that the primary target area in Lsd 6 and the proposed well location in Lsd 6 are separated by the 1.8-metre (6-foot) contour line is not justified, considering the available data.

In conclusion, the Board believes the reservoir potential and limits of the Halfway in Lsd 6 are highly interpretive in that

- the 11-24 well has not proven productive capability,
- the potential net pay of the 11-24 well is speculative and, therefore, the well's position relative to the northeast edge, or any other edge, of the reservoir, is unclear,

- the nearest productive well on trend is approximately 4.0 kilometres to the northwest, and
- reservoir continuity with productive wells to the northwest has not been established.

The Board concludes that wells drilled in the primary and secondary target areas would have equal chances of success.

While the Board does not wish to increase the risk of an exploration play, it concludes that a choice must be made between improved prospects of a successful well and impact on farming.

The Board notes that in two previous decisions regarding target areas (Decisions 80-8[a], D 81-20[b], and D 81-21[c]) certain criteria were established to determine whether it should permit a well to be drilled outside the primary target area.

In Decision 80-8, pertaining to the Grande Prairie area, the Board said, "*Where the landowner had indicated disagreement with the proposed well site, the matter would be examined carefully by the ERCB. The applicant would require good reasons related to conservation, geological considerations and, under special circumstances, equity matters to justify a location outside the primary area.*"

Decision 81-20, pertaining to the Province of Alberta, led to the issuance of SU 1088 establishing northeast target orientation and primary and secondary target areas throughout many of the agricultural areas of the province. In this report the Board said, "*Locating a well in the primary area is preferred and would be automatic with the agreement of the surface landowner. Since the primary area is the target area subscribed to by the majority of the agricultural groups, the Board would expect such agreement would be readily available. For the secondary target area, proposed wells would also be approved if agreed to by the surface landowner. Where such agreement did not exist, the Board would consider the application in the light of the landowner's objections to the location and the applicant's geological or other evidence supporting the request.*"

In Decision 81-21 the Board indicated that Decision 81-20 applied to drilling spacing units of less than one section in the Bonanza area. Accordingly, based on the evidence presented at the hearing and general principles expressed in Decision 81-20, the Board concludes that there is insufficient geological or other evidence to warrant the movement of the well location out of the primary target area and finds that the adverse impact of the proposed location on the farming operation is not warranted, given that the geological prospects for both the primary target and the proposed target are uncertain, with no clear advantage indicated for the proposed target.

4 DECISION

The application for a licence to drill a well in Lsd 6-24-80-12 W6 as proposed by Maynard Energy Inc. is denied without prejudice to any further application which the applicant may wish to make.

DATED at Calgary, Alberta on 6 September 1985.

V. E. Bohme, P.Eng.
Board Member

H. J. Webber, P.Eng.
Acting Board Member

E. R. Brushett, P. Eng., Acting Board Member, concurs with the contents and with the issuance of this report.

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[a] Drilling Spacing Unit Target Area Requirements for Oil and Gas Wells Drilled in the Grande Prairie Area.

[b] Drilling Spacing Unit Target-Area Requirements For Oil and Gas Wells Drilled in the Province of Alberta.

[c] Drilling Spacing Unit Target-Area Requirements for Oil and Gas Wells Drilled in the Municipal District of Smoky River and the Bonanza Area.

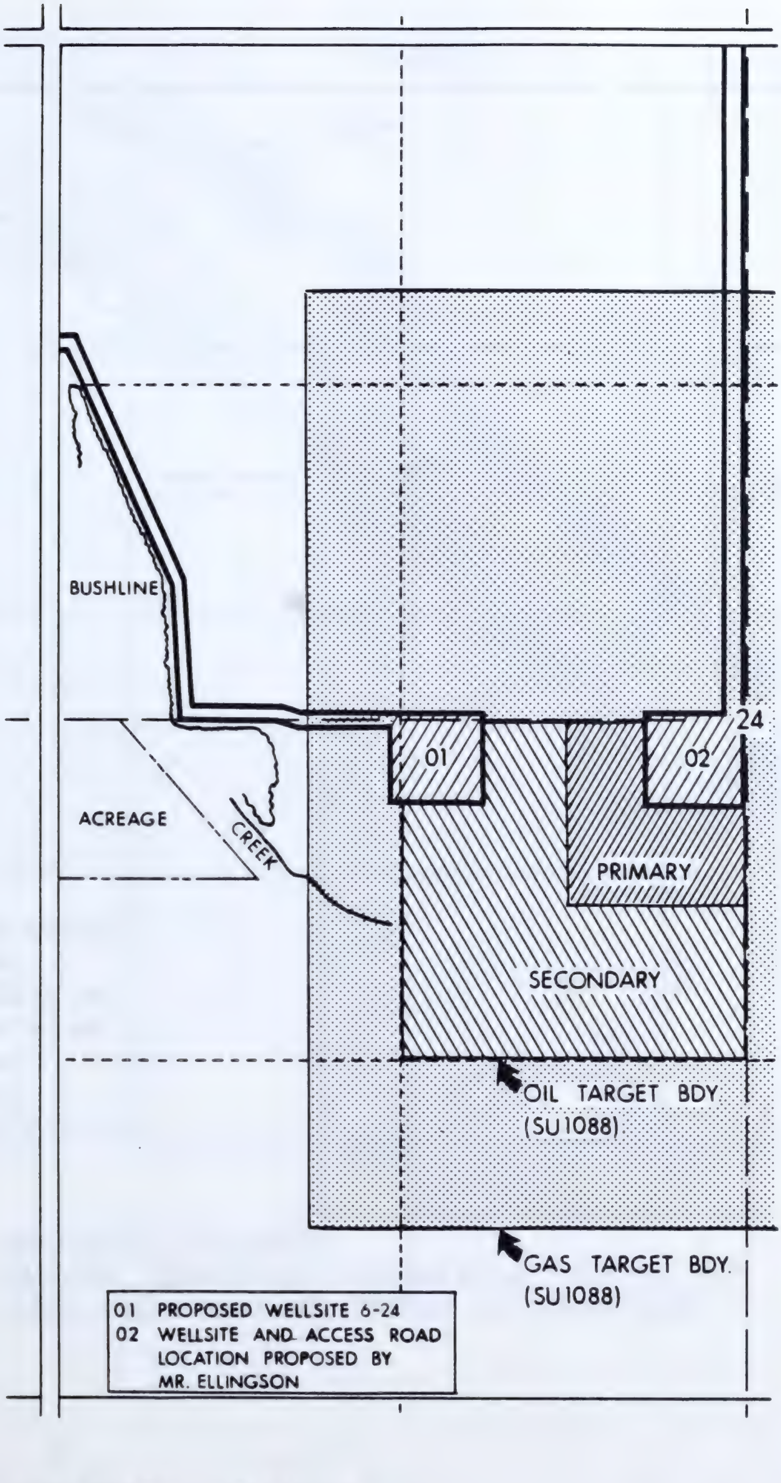


FIGURE 1. APPLICATION NO.850704
PROPOSED WELL SITE, ACCESS ROADS, TARGET AREAS AND OTHER FEATURES IN W 1/2 24-80-12W6M

D 85-37

ERCB

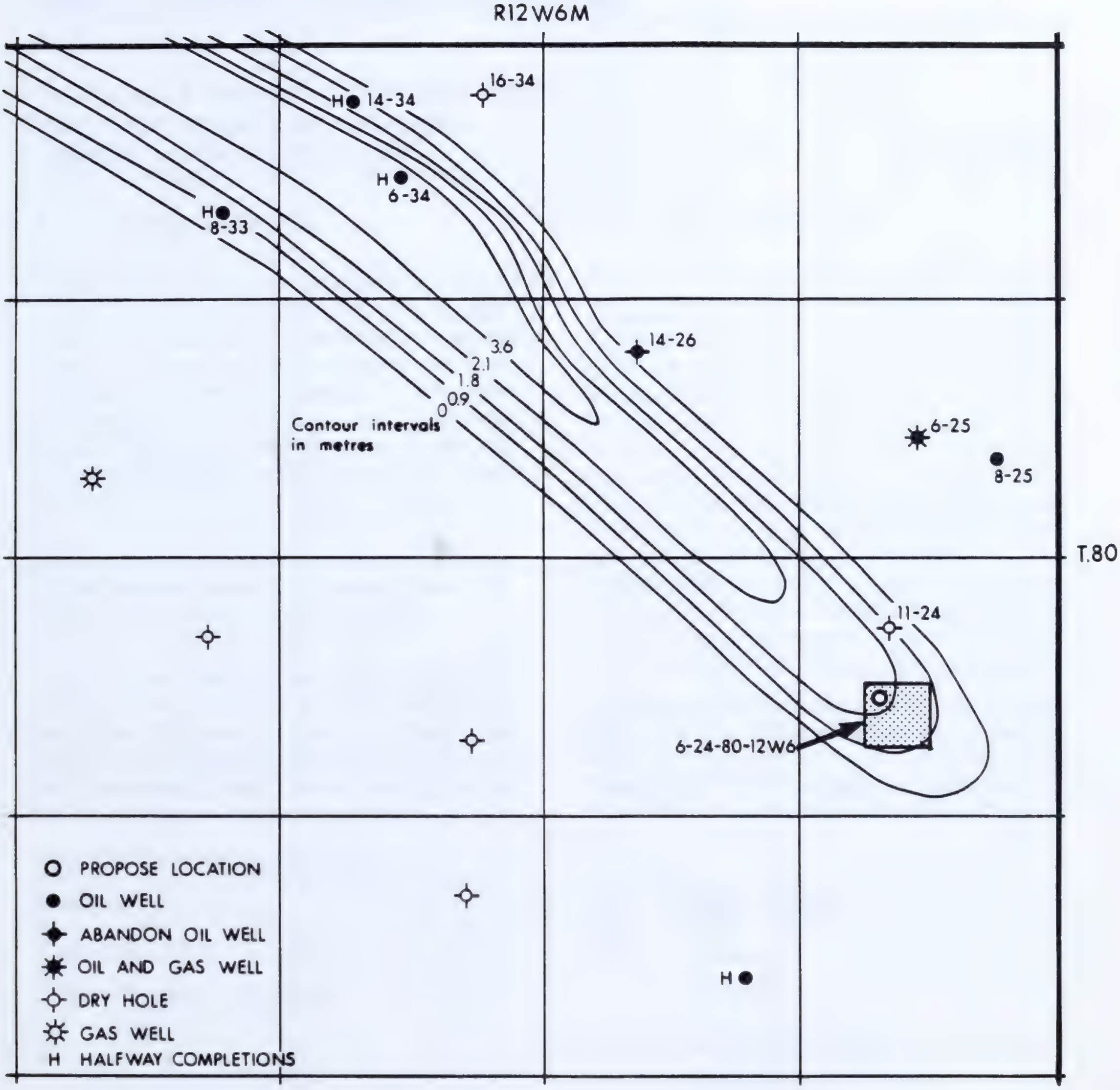


FIGURE 2. APPLICATION NO.850704
HALFWAY FORMATION COQUINA BANK ISOPACH MAP
TAKEN FROM MAYNARD ENERGY INC. SUBMISSION

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

PUBLIC MEETING TO CONSIDER LANDS INCLUDED IN CITY OF CALGARY SOUR GAS CONSTRAINT AREA

Decision D 85-38
Proceeding 850680

1 INTRODUCTION

A "sour gas constraint" area was applied by the City of Calgary to lands southeast of Calgary city limits (as per Figure D 85-38, attached) in the fall of 1982 in recognition of sour gas reserves and potential conflict with urban development in the area. Frederick J. Ollerenshaw requested that the Energy Resources Conservation Board (ERCB) review the sour gas constraint area insofar as it affects his lands in sections 23 and 24 of township 22, range 29, west of the 4th meridian.

The ERCB held a public meeting on 7 August 1985 in Calgary, Alberta, before G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and C. J. Goodman, P.Eng.

Those who participated in the meeting are listed in the following table. Robert and Betty McKinstry, Charles and Delores Workman, Linda and Guy Paradis, Les and Aileen McKeagg, Lorne and Phyllis Thompson, and Florence and Gerald White submitted letters but did not actively participate at the meeting.

2 GENERAL MATTERS

2.1 ERCB Involvement in the Planning Process

Questions were raised at the meeting respecting the role of the ERCB in the planning process. Upon request, the ERCB provides advice to planning authorities in Alberta on matters within its jurisdiction. This advice takes the form of identifying existing gas production facilities and determining the extent of setbacks pursuant to ERCB Interim Directive ID 81-3. The setbacks are based on hydrogen sulphide (H_2S) content of the product being produced or transported. In a limited number of situations, the ERCB has provided planning authorities with information on areas where proven sour hydrocarbon reserves exist and where the ERCB is of the view that serious land use conflicts may occur if urban development proceeds into such areas.

In cases where the ERCB has identified areas underlain with proven sour hydrocarbon reserves for planning authorities, it was not the intention of the ERCB that these areas be automatically eliminated or constrained from possible urban development. Rather, it was the

PARTICIPANTS AT THE MEETING

Principals	Representatives
F. Ollerenshaw	S. Carscallen
Canterra Energy Ltd. (Canterra)	C. H. Morel H. D. Logie, P.Eng. W. G. M. Bell, P.Eng. R. G. Leishman, P.Geol. E. J. Dyck, P.Eng.
C. Soutzo and A. Soutzo (the Soutzos)	M. A. Putnam, Q.C.
R. Bonnycastle J. Burgess	R. Armitage
City of Calgary (the City)	E. C. Brown
Energy Resources Conservation Board staff	H. R. Hansford E. R. Brushett, P.Eng. E. Smith, P.Eng. C. Olesen

ERCB's intention that the planning authority, in making development planning decisions, be able to consider this factor as one of a number of factors.

The significance of sour reserves in land development will vary for different situations depending on the amount of H_2S that might be released, the volume of hydrocarbon reserves to be recovered, alternative ways of recovering those reserves, the expected producing life, and other relevant matters. The ERCB assumes that other planning factors such as the economics of urban development, the availability of alternative lands, and planning and growth strategies are also considered by the planning authority.

The fact that the ERCB identifies an area as underlain by sour hydrocarbon reserves does not mean that it will automatically license any production facilities within that area, nor does it mean that the resources will necessarily be exploited. The ERCB considers all applications for such facilities in its normal fashion, responding to specific circumstances at the time of the proposal. It is only after consideration of the circumstances and a finding that the proposed facilities are in the public interest that applications would receive ERCB approval.

The ERCB believes that it is appropriate to identify, and that it will continue to identify upon request: existing sour facilities, applicable setback distances pursuant to ERCB ID 81-3, and areas where proven sour hydrocarbon reserves exist and have a high potential for serious land use conflicts. Such information is relevant to good planning decisions.

The ERCB continues to encourage mineral owners to prove up and produce sour reserves underlying potential urban areas as soon as feasible. This improves planning decisions, as the resource information will be more complete and also will allow for the staging of urban growth and development as the resource is depleted.

Reservoir depletion is an important factor that should be incorporated into urban growth and development strategies. As the urban planning time frame is in the order of 20 to 30 years, considerable reservoir depletion may occur over this interval. Any real or perceived restriction to development will decrease as reservoir depletion occurs.

2.2 Authority to Give Advice

It is the opinion of the ERCB that providing information on existing facilities and setback distances applicable to those facilities pursuant to ERCB ID 81-3 is within the ERCB's mandate.

The ERCB also believes it has the authority to provide advice to planning authorities respecting the location of areas of sour hydrocarbon reserves when requested. The ERCB is the agency of the Provincial Government charged with appraisal of hydrocarbon reserves of Alberta, the recording and dissemination of information respecting those reserves, and with their economic, orderly, and efficient development in the public interest. The ERCB believes the existing liaison between planning authorities and itself, and provision of reserves information, is consistent with these responsibilities and contributes to an efficient and effective planning procedure.

2.3 Notification of Affected Parties

Certain participants in the meeting stated that they suffered financial losses because their lands were constrained from urban development for many years. The ERCB identifies areas of existing or likely serious land use conflicts involving sour reserves and provides this as information to planning authorities at their request. Since this information is intended as only one factor among several considered in the planning process, the ERCB sees little merit in developing a formal public procedure to review information routinely provided in response to requests from planning authorities.

The ERCB understands that the current process normally provides the public and affected landowners an opportunity to be heard in a public forum where an area plan or land use by-law is formally adopted, and that ample notice is given of such proceedings.

The ERCB is prepared to participate in such forums by describing the basis of information given, where it is at issue. Such information is not kept confidential. If an affected landowner has concerns regarding advice provided to planning authorities and if there is information which could alter that advice, the ERCB is prepared to reconsider the matter in a manner similar to that used in this instance.

3 REVIEW OF SOUR GAS CONSTRAINT AREA

3.1 Participants' Views

Mr. Ollerenshaw, owner of section 23 and the west half of section 24, recognized that the setback distance pursuant to ERCB ID 81-3 for the well located on section 24 effectively removed the section from urban development for the life of that facility. However, it

was Mr. Ollerenshaw's opinion that section 23 did have development potential and would likely have been included in the City of Calgary's Homestead Subdivision had it not been for the sour gas constraint designation. This was supported with material indicating that the western portion of section 23 could be serviced with the existing sewer system using gravity flow, and that it was situated in an acceptable location relative to existing and designated transportation corridors.

Canterra was of the view that the sour gas constraint area, as designated by the City, was underlain with proven and potential sour reserves but did not comment specifically as to the need, if any, to modify the boundaries. Canterra indicated that of the lands on which it had mineral interests, the most prospective locations for future wells were in sections 18, 19, and 25; however, as additional reservoir information was obtained by producing existing wells, this development scenario could be modified. Due to the limited capacity of its gas processing facility at Okotoks, Canterra did not contemplate drilling any new wells in the area for about 2 to 3 years.

Within the sour gas constraint area, the Soutzos own the portions of sections 11 and 12 north of the Bow River and sections 13 and 14. It was their opinion that sections 11 and 14 would have been part of the City Planning Department's recommendation for annexation if it were not for the sour gas constraint. They were primarily concerned that they had not had any input into such a designation being placed upon their lands and that this designation had a negative impact upon the value and uses of their property. They contended that the setback distances were adequate and therefore there was no need for the designation of a sour gas constraint area. If a constraint area were to exist, the Soutzos requested that the present boundaries be modified and reduced to exclude sections 11, 14, 23, and 24.

Mr. Bonnycastle and Mrs. Burgess, who have an interest in sections 8 and 5 in 22-28 W4M, north of the Bow River, requested that their lands be removed from the sour gas constraint area on the basis that these lands were well outside the ERCB's setback distances.

Robert and Betty McKinstry, Charles and Delores Workman, Linda and Guy Paradis, Les and Aileen McKeagg, and Lorne and Phyllis Thompson expressed concern about resale value of their property and the safety of areas within a sour gas constraint area. Florence and Gerald White requested, by letter, that the sour gas constraint area be removed from their land.

4 RECOMMENDATIONS

Based on the extent of the reserves underlying the subject area and having consideration for the location of existing sour gas facilities and associated setback distances, and for Canterra's evidence regarding the most prospective future locations, it is the opinion of the ERCB that the sour gas constraint area can be reduced. It therefore recommends that sections 14, 23, and 26 in 29-22 W4M, on the west side, and sections 5, 7, 8, 17, 29, and 30 in 28-22-W4M, to the east of the sour gas facilities, be excluded from this constraint area.

Figure D 85-38 shows the outline of the reserves as estimated by the ERCB, existing and possible future facilities and the related setback requirements, and the lands which the ERCB believes could be excluded from the constraint area. It is recognized that sour gas development plans for the area could change. It is also recognized that the excluded lands would not all immediately undergo residential development. If specific urban development plans for such lands are proposed in the future, the ERCB believes they should be assessed having regard for the sour gas reserve and facility situation at the time of consideration.

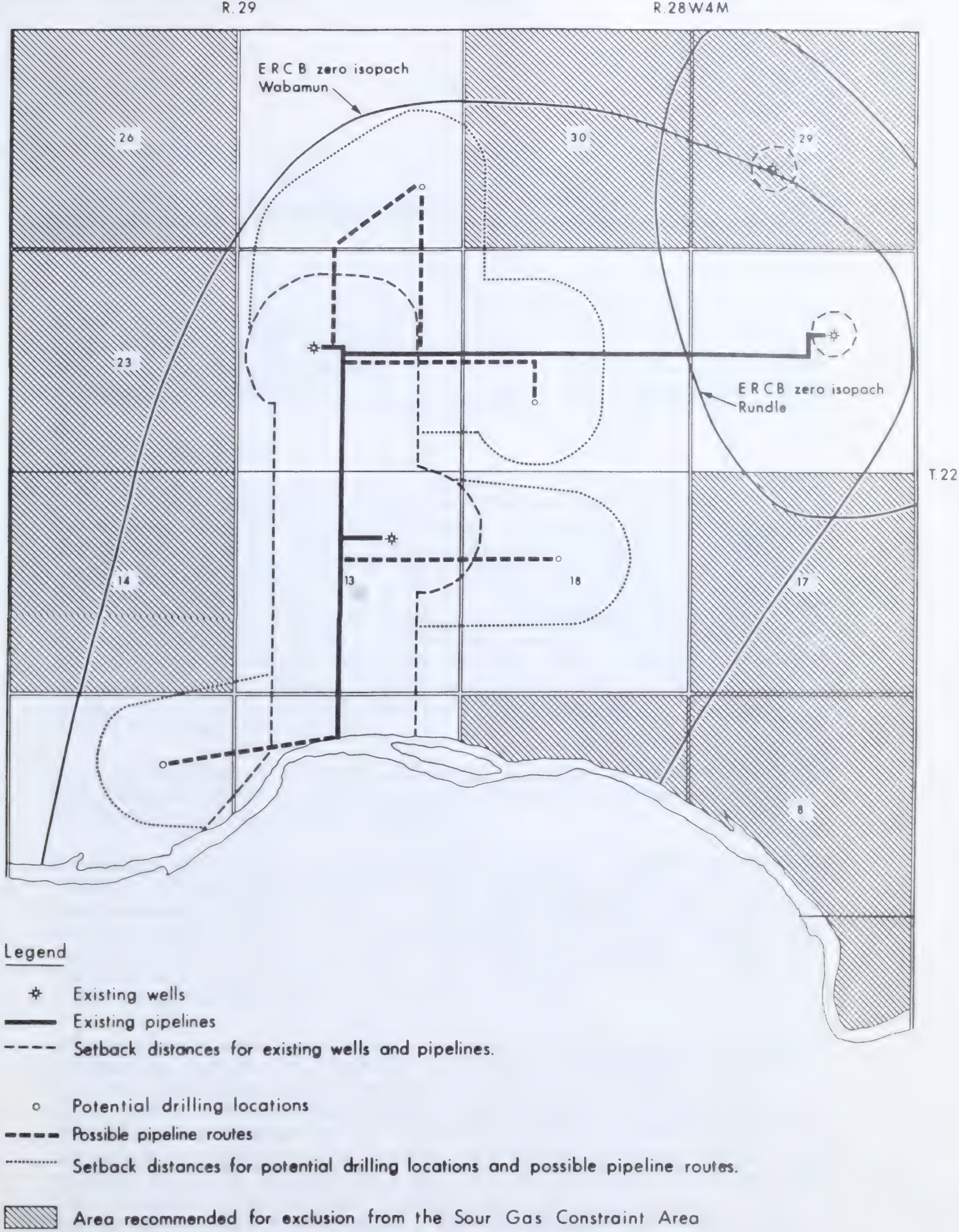
DATED at Calgary, Alberta, on 30 September 1985

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

V. E. Bohme, P.Eng.
Board Member

C. J. Goodman, P.Eng.
Board Member



CITY OF CALGARY SOUR GAS CONSTRAINT AREA

D85-38

ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

ALBERTA ENERGY COMPANY LTD. AND
COMINCO CHEMICALS AND FERTILIZERS
INDUSTRIAL DEVELOPMENT PERMIT
TO MANUFACTURE AMMONIA

Decision D 85-39
Application 850703

1 INTRODUCTION

Alberta Energy Company Ltd. (AEC) and Cominco Chemicals and Fertilizers (Cominco) applied, pursuant to section 30 of the Oil and Gas Conservation Act (Act), for an industrial development permit authorizing the annual use of 768 million cubic metres (10^6 m^3) of hydrogen as raw material and 14.1 x 10^6 m^3 of natural gas as fuel to produce anhydrous ammonia at a new plant to be constructed near Joffre. Approximately 256 x 10^6 m^3 per year of nitrogen would be obtained from the Linde-Union Carbide plant near Prentiss for use as raw material. The proposed plant would produce up to 350 thousand tonnes of ammonia per year when operating at capacity. A 20-year permit term was requested.

A public hearing of the application was held in Red Deer, Alberta, on 23 September 1985, with G. J. DeSorcy, P.Eng., V. E. Bohme, P.Eng., and T. F. Homeniuk, P.Eng., sitting.

On commencement of the hearing, the Board heard a request by Mr. Dean Chessor, a local resident, and Preserve Agricultural Land (PAL), for postponement of the hearing. Mr. Chessor stated that the application did not deal with the impact of proposed off-site loading facilities, and that persons who would be directly affected by the loading facilities and related pipelines had not learned of their locations until 13 September 1985.

The applicant argued that, until the Board issues a permit for the project as applied for, there is no need for the off-site facilities; and that since two alternative plant sites are proposed in the application, a favourable decision from the Board would be required before the end points for the pipelines would be defined. The applicant also stated that two alternatives for loading facilities are identified in the application, one "on-site" and one "off-site", and that details of the on-site facility are discussed in the Environmental Impact Assessment. Notwithstanding its "project update" of 15 September 1985, announcing that ammonia would be piped north

from the Joffre plant site to a product storage and loadout facility on the Canadian Pacific rail line, the applicant requested the Board to evaluate the project on the basis of evidence respecting the on-site alternative.

The Board decided it needed to hear the evidence respecting the application before it could decide on the matter of postponement suggested by Mr. Chessor and PAL. It advised the participants that the hearing would proceed and would be adjourned on an indefinite basis at its conclusion. The Board would then consider the evidence to determine what, if any, additional information might be required to decide the application. The Board advised that it would issue its decision in a report.

The parties who appeared at the hearing are identified in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Alberta Energy Company Ltd. (AEC) Cominco Chemicals and Fertilizers (Cominco) D. A. Holgate	L. A. Collins, P.Eng. R. E. Ward J. G. Whitham, P.Eng. K. L. Beynon, P.Eng. J. Fulford R. Towler, P.Eng.
D. Chessor	D. Chessor
Preserve Agricultural Land (PAL) J. W. Hainsworth	J. W. Hainsworth D. Chessor G. Friesen
Canadian Fertilizers Ltd. (CFL)	J. I. Parker
The Alberta Gas Ethylene Co. Ltd. (AGEC)	C. A. Read
Energy Resources Conservation Board staff H. R. Hansford D. D. Fraser M. E. Mumby G. J. Schroter	

2 ISSUES

The Board believes that the issues raised by the application are as follows:

- availability of feedstock and the efficient use of natural gas and hydrogen,
- marketing of ammonia,
- economic impacts,
- the preferable plant location,
- agricultural impact, and
- environmental and social impacts.

The following sections outline the information and evidence presented with respect to the issues and the Board's consideration of the information. Where the information and evidence are sufficiently complete to allow the Board to reach conclusions respecting the issues, these conclusions are stated.

3 AVAILABILITY AND EFFICIENT USE OF FEEDSTOCK

AEC/Cominco stated that natural gas for the plant's process heating requirements would be purchased under long-term contracts, and that discussions were being held with potential Alberta suppliers. Pipeline transportation of the required gas supplies is also being discussed with utilities presently servicing the Joffre area. The total volume of gas required by the proposed plant over a 20-year term would be 275.4×10^6 m^3. This volume would provide 10 per cent more gas than the normal design production rate requirements of the plant, to allow for various operating contingencies.

Hydrogen feedstock, obtained from the Joffre ethylene facilities owned by AGEC, would be transported to the ammonia plant by pipeline. The hydrogen is currently being recycled to the AGEC ethane cracking furnaces as fuel in the production of ethylene. The total volume of hydrogen required as raw material for the ammonia plant over a 20-year term would be 15.36 billion cubic metres (10^9 m^3). The hydrogen removed from AGEC would be replaced by approximately 305×10^6 m^3 of natural gas annually.

Nitrogen feedstock would be obtained from the nearby Linde-Union Carbide plant. The nitrogen is presently being vented to atmosphere.

The Board is satsified that it received sufficient information respecting these issues to reach conclusions. It believes that the proposed plant, using available hydrogen and nitrogen as feedstock, represents efficient use of available resources and technology. It is also satisfied that sufficient natural gas is available for the proposed plant and as hydrogen replacement fuel at the AGEC plant.

The Board notes that gas supply and transportation arrangements have not been completed. In the event the proposed plant is approved, AEC/Cominco would be required to advise the Board with respect to gas supply arrangements. Pipeline facilities for transportation of the fuel and feedstock would require Board approval and would need to be applied for by separate applications.

4 MARKETING OF AMMONIA

AEC/Cominco submitted that it has had to purchase ammonia to supplement supply shortages in the recent past, has been unable to secure a required supply of purchased ammonia during the past year, and has had to cut back on urea fertilizer production in order to free up ammonia for supply requirements. The applicant contended that it needs the extra productive capacity in order to retain its position in the marketplace. The new production would alleviate Cominco's supply shortage of anhydrous ammonia required for direct application fertilizer purposes and also allow Cominco to increase urea production at its Carseland, Alberta, plant.

AEC/Cominco provided an estimate of fertilizer demand within the Western Canadian market area and the northwest and mid-west U.S. market areas. The evidence indicated that Western Canadian demand would increase at a substantial rate over the 1985-1990 period, while the U.S. market areas would experience marginal increases over the same period, returning total demand in those areas to levels of the early 1980s. The applicant indicated that, even though the forecast demands in the Western Canadian and U.S. market areas appear to be nearing the total of the current and approved capacities within the marketplace, it was confident that Alberta producers would be able to compete effectively. The applicant contended that some of the capacity in the U.S. marketplace is currently shut down due to inefficient operations and that this capacity would probably remain shut down, allowing more flexibility for Alberta exports than the figures would indicate.

None of the interveners questioned the need for the project.

The Board recognizes the position Cominco is in and agrees that Cominco's marketing distribution network needs to have additional productive capacity to compete effectively in the marketplace. The

Board also recognizes that, due to the high ratio of productive capacity versus demand in the Western Canadian and northwestern U.S. areas, there will probably be a need for Alberta producers to compete for market share in the mid-west U.S. states in order for all of Alberta productive capacity to be utilized.

The Board believes that, in view of the marketing evidence provided by the applicant and the absence of any contrary evidence by any other Alberta ammonia producers, the opportunities to market the production from the proposed project would be available.

5 ECONOMIC IMPACTS

The applicant stated that the total capital expenditure required to start up the project would be $80 million. Of that total, $44 million would be spent within Alberta, of which $12 million would be spent within the Red Deer-Lacombe area. Construction of the project would take place over a 2-year period, with an average work force of 140 and a peak work force of 240. Approximately 26 full-time personnel would be employed during the operational phase of the project. AEC/Cominco stated that the total direct and indirect economic impact of the project over the requested 20-year permit term would amount to $1.3 billion.

The Board did not undertake a detailed comparative calculation of the economic impact of the project. It considers the information provided by the applicant to be adequate and, upon review, accepts that the economic benefits generated by the project would be substantial, probably exceeding $1 billion over the life of the project.

6 THE PREFERABLE PLANT LOCATION

AEC/Cominco asked the Board to consider its application on the basis that the loading facilities would be located at the plant site. It advised the Board that it is also investigating off-site locations for the loading facility. It identified an area north of Highway 12, near Chigwell, as one such site. It therefore requested that its application be granted without prejudice to any future application that it might make with respect to off-site loading facilities.

The applicant provided information for four sites that it had investigated. Two of the sites, identified as Site 3 in section 11, township 39, range 23, west of the 4th meridian (11-39-23 W4M) and Site 4 in 22-39-22 W4M, were rejected outright because longer pipelines to transport fuel and feedstock would increase the total cost of the project by some $15 million. The applicant advised that it would not proceed with the project if the plant were required to be located at either Site 3 or Site 4.

The applicant stated that the remaining two sites, Site 1 in NE 1/4 Sec 19-39-25 W4M and Site 2 in S 1/2 Sec 3-39-25 W4M, are similar. It selected Site 2 as the preferred site for geotechnical and socio-economic reasons. If Site 1 were chosen, some physical modification to Jones Creek, which traverses the site, might be required, and some beaver habitat might have to be removed.

The Board notes the applicant's submission that, if the plant were required to be located at either Site 3 or Site 4, the project would not proceed. Therefore, those possible locations are not before the Board and will be given no further consideration. The question the Board must address is whether the proposed plant, and on-site loading facility, located at either Site 1 or Site 2, is in the public interest, having regard for the "benefits" that would flow from the plant and the resulting negative impacts and other "costs".

The Board accepts the applicant's view that Site 1 and Site 2 are similar, but that Site 2 has modest advantages over Site 1. It further notes that none of the interveners identified any preference for either one of these sites over the other.

The Board will now focus its attention on Site 2 and will further assess the acceptability of the project by reviewing the agricultural, social, and environmental impacts that would result. These latter matters are discussed in the following sections.

7 AGRICULTURAL IMPACTS

The plant would occupy some 6 hectares of land. The loading facility would require an additional 12 hectares. The applicant stated that it would improve some nearby poorer quality land such that overall agricultural production would not be decreased. It identified a nearby slough area that would be improved.

The applicant stated that it is in the process of negotiating purchase of the required land.

The applicant rejected the interveners' argument that agricultural land would also be taken out of production to accommodate increases in population and support services that would result from constructing the plant in the area. It submitted that the City of Red Deer already had sufficient development land, infrastructure, and services to accommodate the additional people.

PAL and Mr. Chessor argued that the plant should be located at either of the two sites that were rejected by the applicant. They stated that the rejected sites were in areas of poor quality agricultural land and that use of good quality agricultural land for an industrial plant could, therefore, be avoided.

PAL also argued that the agricultural land base would be reduced to accommodate the increase in population and support services. It submitted that the proposed plant, and its impact on the agricultural land base, should be considered as part of the overall impact of industrial development in the area. PAL stated that its primary concern about the plant related to the use of agricultural land for industrial development.

The Board believes it has sufficient evidence before it to deal with this issue. It notes that some 18 hectares of land are required for the plant and loading facilities. It further notes that the applicant proposes to improve nearby poor quality land so that overall capability for agricultural production is not decreased. Therefore, the Board concludes that the impact of the plant and loading facilities on the agricultural land base and on production would be minimal, if any. Respecting the contention by the interveners that the use of good agricultural land for the plant could be avoided by utilization of Sites 3 or 4, the Board again notes that a plant at either of those sites would not be proceeded with. The use of agricultural land would thus be "avoided" but the benefits of the project would also be foregone.

The Board considered PAL's contention that the agricultural land base would be reduced to accommodate the increase in population and support services. It notes that the City of Red Deer has sufficient development land and infrastructure to accommodate any requirements associated with the proposed plant. Even if this were not the case, it is the Board's view that any additional land required to accommodate growth as a result of the proposed plant would be modest.

8 ENVIRONMENTAL AND SOCIAL IMPACTS

The applicant stated that, because the feedstocks for the proposed plant are high-purity hydrogen and nitrogen, the process operations required in a conventional ammonia process to produce these gases from air, natural gas, and steam are not required. Since these process operations are the major sources of air and water emissions, the emissions from the proposed plant would be significantly less than from a conventional plant of the same capacity. Atmospheric emissions would be well within Alberta Environment ambient air quality objectives. A monitoring program would be carried out during plant operations in accordance with Alberta Environment regulations.

Plant water requirements would be obtained from a water well. Waste water would be held in ponds prior to discharge to the Red Deer River. The water would be monitored and controlled prior to discharge.

Noise levels at the plant site would be within maximum permissible levels established by the Energy Resources Conservation Board. During the construction phase of the project, noise levels would increase temporarily at the plant site and on roads around the plant site due to increased traffic from construction-related vehicles. These activities would be a temporary impact and would generally occur during daylight hours.

The plant product would be transported by railway and truck. Rail traffic would average 22 rail cars once per day, five days a week or 16 rail cars once per day, seven days a week. During peak seasons, typically April-May, and October, product would be moved by truck to local dealers for immediate distribution. During these periods, truck traffic could peak at 100 loads per day with an average of 45 loads. During the off season, truck traffic would drop to between zero and five loads a week.

The applicant stated that, subject to a change to off-site loading facilities, the rail traffic would move on the adjacent C.N. track. Truck traffic would tend to distribute in all directions from the plant. Routes for truck traffic would be designated with input from the County of Lacombe (County) to ensure suitable routing.

The applicant stated that it would not provide an on-site construction camp due to the availability of local construction workers and services in the Red Deer-Lacombe area.

Mr. Chessor expressed concern regarding noise from the truck traffic associated with transporting the product to local suppliers. His concern was specifically related to truck traffic from a loading facility located near Chigwell; however, he suggested that a similar impact would occur, only in a different area, if the loading facility were located at the proposed plant site.

No other concerns were expressed regarding environmental or social impacts.

The applicant, during the hearing, clarified that it was asking the Board to assess the proposed plant with an on-site loading facility, rather than an off-site facility for which little information was given in the application. It stated that, if it subsequently wished approval of an off-site facility, it would at that time submit separate pipeline and related applications to the Board. Given these circumstances and the evidence received, the Board is satisfied that it can make an assessment of the environmental and social impacts that might result if the application is approved.

The Board is satisfied that environmental impacts would be negligible and that all provincial environmental standards would be met at the proposed plant. It is also of the view that the water requirements for the plant would not cause a serious negative impact on the availability of water in the area.

Recognizing the planned "buffer area" that would surround the proposed plant and within which residents would not be located, noise levels should not create a significant problem. Additionally, the Board heard no evidence suggesting that the incremental population associated with the proposed plant, either at its peak during construction or in the operating phase, could not be accommodated or would create social problems.

The most significant impact would likely result from train and truck traffic associated with the shipment of the products from the proposed plant. The loading facility would involve some movement of rail cars on-site while loading, but this would be relatively remote from the closest neighbours due to the planned buffer zone. There would be increased rail traffic into and out of the plant, but this would be limited to less than one additional train per day.

Respecting trucks, although the traffic would be heavy during peak periods, it would not be significant for about three-quarters of the year. The peak traffic would coincide with the periods of greatest activity in the local agricultural community, so incrementally, the impact would likely be reduced. Additionally, the applicant would use traffic routes designated by the County, which would presumably also serve to reduce impacts.

In total, with respect to trains and truck traffic, the Board believes that with some care and planning on the part of the proponents of the project, the impact on the local community can be held to a reasonable level.

9 CONCLUSIONS AND DECISION

The Board believes that it received sufficient evidence in the application and at the hearing to make a decision. Therefore, although it adjourned the subject proceeding sine die on 23 September 1985, it does not intend to reopen the hearing and now considers it complete.

The Board is satisfied that sufficient energy resources are available for the proposed plant and that they would be used in a very efficient manner. It believes that, over the long term, the product from the plant could be marketed, and recognizes that Cominco has an immediate need for more product for its marketing network.

The Board is of the view that the proposed facility would have a substantial positive economic impact on the province over its intended life. It would also create a significant number of jobs at a time when the unemployment rate in the province is extremely high.

In arriving at its decision, the Board must weigh against these positive aspects of the proposal, the negative impacts that would accompany it. Given the commitment of the applicant to upgrade the productivity of certain lands, the Board does not believe that the impact on agricultural land would be significant. The increased traffic, particularly from trucks, would be substantial at certain times during the year, but in the Board's judgement would not be so great as to override the benefits of the proposed project. The Board is satisfied that adherence to all requirements of the Board and Alberta Environment would limit the project's environmental impacts to minimal and acceptable levels.

Having regard for the above stated conclusions the Board is prepared to approve the proposed ammonia plant, including the applied-for on-site loading facility. It will seek the necessary authorization from the Lieutenant Governor in Council and upon receipt will issue an industrial development permit to AEC/Cominco.

DATED at Calgary, Alberta, on 1 November 1985.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

V E Bohme

V. E. Bohme, P.Eng.
Board Member

T Homeniuk

T. F. Homeniuk, P.Eng.
Acting Board Member

APPENDIX
FORM OF PERMIT*

IN THE MATTER of the Oil and Gas Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980; and

IN THE MATTER of an industrial development permit to Alberta Energy Company Ltd. and Cominco Chemicals and Fertilizers authorizing the use within Alberta of hydrogen and natural gas produced in Alberta for the production of ammonia

INDUSTRIAL DEVELOPMENT PERMIT NO. AEC 85-1

WHEREAS Alberta Energy Company Ltd. and Cominco Chemicals and Fertilizers have applied in Application No. 850703 to the Energy Resources Conservation Board for an industrial development permit, pursuant to section 30 of the Oil and Gas Conservation Act, authorizing the use of hydrogen and natural gas produced in Alberta for the production of ammonia in Alberta; and

WHEREAS the Board, upon inquiry into the application, is of the opinion that the granting of this industrial development permit for the use of hydrogen as raw material and natural gas as fuel for production of ammonia is in the public interest, having regard to, among other considerations, the efficient use without waste of energy resources and the present and future availability of hydrogen and natural gas in Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council numbered and dated , has authorized the granting of the permit.

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* This is only a form of permit. The permit, when issued, may have minor variations from that set out here.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter O-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Alberta Energy Company Ltd. and Cominco Chemicals and Fertilizers (hereinafter called "the Permittees") authorizing the use of hydrogen as raw material and natural gas as fuel for production of ammonia, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. This permit is for the use, in Alberta by the Permittees, of hydrogen as raw material and natural gas as fuel for the production of approximately 350 000 tonnes per year of ammonia, generally as described in the application to the Board dated 28 June 1985.

2. The plant facilities at which ammonia will be produced shall be located in Section 3, Township 39, Range 25, West of the 4th Meridian.

3. Subject to compliance by the Permittees with the terms and conditions hereof, this permit shall be for a term commencing on the date hereof and ending on 31 March 2007.

4. The quantities of hydrogen and natural gas that may be used in the industrial operation referred to herein shall not exceed 768 000 000 cubic metres per calendar year and 14 100 000 cubic metres per calendar year, respectively.

5. The quantities of gas for the purpose of this permit shall be on the basis of a gas free of water vapour and having a higher heating value of 37.4 megajoules per cubic metre.

6. All hydrogen and natural gas used in producing ammonia pursuant to this permit shall be measured by or on behalf of the Permittees in a manner satisfacory to the Board, and the volumes of hydrogen used as raw material and natural gas used as fuel and of ammonia produced shall be separately reported to the Board in a manner satisfactory to the Board.

7. The Permittees shall obtain the approval of the Board of any major changes in design of the plant facilities.

8. (1) The Permittees shall satisfy the Board prior to 15 January 1986, or such other date as the Board upon application by the Permittee may stipulate, that arrangements for the financing of its proposed project have been completed.

(2) The Permittees shall satisfy the Board prior to 1 March 1986, or such other date as the Board upon application by the Permittees may stipulate, that construction of its proposed facilities has commenced.

(3) The Permittees shall satisfy the Board prior to 1 September 1986, or such other date as the Board upon application by the Permittees may stipulate, that arrangements for the supply of the necessary hydrogen and natural gas volumes have been completed.

9. During construction of the industrial operation referred to herein, the Permittees shall report to the Board semi-annually, in a manner satisfactory to the Board, with respect to the progress of construction.

10. The Permittees shall operate the facilities in a manner that results in

(a) the maximum practically obtainable efficiency in the use of hydrogen and natural gas for the manufacture of ammonia, and

(b) the maximum practical conservation of hydrogen and natural gas.

11. The Permittees shall not

(a) assign this permit, or

(b) release from their control the operation of the plant,

without the consent in writing of the Board which consent may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

12. (1) Attached hereto as Appendix A, and made part of this permit, is the Order of the Lieutenant Governor in Council authorizing the granting of this permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the Order of the Lieutenant Governor in Council set out in Appendix A.

13. Where it appears to the Board or the Lieutenant Governor in Council that the Permittees have contravened or failed to comply with any terms or conditions contained in this permit or any relevant statutes or regulations of Alberta,

(a) the Board shall review the permit and with the approval of the Lieutenant Governor in Council may cancel the said permit or take such other remedial measures as considered suitable by the Board and the Lieutenant Governor in Council in the circumstances, or

(b) the Lieutenant Governor in Council may amend, vary, add to or replace any terms or conditions contained in this permit.

14. Notwithstanding the provisions hereof, the Permittees shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this day of , 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY WESTRIDGE PETROLEUM CORP.
AND WESTERN COMPRESSION SYSTEMS LTD.
FOR APPROVAL OF COMPETING GAS CONSERVATION
AND PROCESSING SCHEMES IN THE
PREVO-CYGNET AREA

Decision D 85-40
Application 850679
and 850844

The Board received Application 850679 from Westridge Petroleum Corp. (Westridge) for approval to construct and operate a sweet gas processing plant in Lsd 5-1-39-1 W5M with a raw gas inlet rate of 423×10^3 m^3 per day, and Application 850844 from Western Compression Systems Ltd. (Western Compression) for approval to construct and operate a sweet gas processing plant in Lsd 13-22-39-1 W5M with a raw gas inlet rate of 225×10^3 m^3 per day.

The applications were considered by the Board at a public hearing in Red Deer on 2, 16, 17, 22, and 23 October 1985 with N. Strom, P.Eng., C. J. Goodman, P.Eng., and M. J. Bruni, sitting. Those who appeared at the hearing are listed in the attached table.

A number of area residents in the vicinity of each of the proposed sites intervened and appeared at the hearing. Both sites, and other existing production facilities in the area were visited as part of the hearing on the morning of 22 October 1985.

The Prevo-Cygnet area, which extends from the western perimeter of the City of Red Deer to the eastern shores of Sylvan Lake, has been the scene of relatively active oil and gas drilling in the past two or three years, the results being a number of relatively small oil discoveries and the discovery of some non-associated gas. Currently there are approximately 55 wells that are producing oil and flaring substantial volumes of gas that is produced with the oil. In August 1985 the rate of solution gas flaring was approximately 83.1×10^3 m^3 per day. Also at the northwest end of the area, there is some non-associated gas that is being produced and marketed under an existing natural gas contract.

The Westridge application contemplates installation of a plant of sufficient size to process all of the low-pressure oilfield gas that would be gathered from this entire area plus currently producing non-associated gas and potential additional production of non-associated gas located in the general Prevo-Cygnet area. It submitted evidence showing that upwards of 80 per cent of all the currently flared low-pressure oilfield gas was dedicated to its project.

The Western Compression application contemplated construction of a plant of sufficient size to accommodate approximately half the total gas that might be available in the area. Western Compression contemplated limiting the size of its plant to meet the volumes dedicated by producers. At the time of the hearing it estimated that 20 per cent of the low-pressure oilfield gas was committed to its project. While the Western Compression plant was initially sized at only about half that of the Westridge plant, the Western Compression evidence indicated that minor modifications would be needed to increase the plant capacity to accommodate all of the expected gas production in the area.

All participants in the hearing, including the two applicants, petroleum operators, and local landowners agreed that conservation of low-pressure oilfield gas should be initiated as soon as practical. On that basis and as a means of minimizing winter construction requirements, both applicants and other participants urged the Board to reach a decision as expeditiously as possible on each of the applications. Evidence submitted at the hearing by Westridge indicated that initially approximately half of the gas available for processing would come from low-pressure oilfield operations with the remaining half coming from high-pressure non-associated gas sources. However, the evidence from both applicants concerning projections of probable volumes of solution gas per se, associated gas that is produced with the oil (ie. gas cap gas), and non-associated gas that would require processing, were not documented in such a way as to permit clear assessment of the volumes available from these three potential sources. Especially on the matter of associated gas which would occur from simultaneous production of a gas zone along with production from an adjoining oil zone, there is some uncertainty whether contracts for sale of that kind of gas would be forthcoming. The testimony by producers at the hearing only indicated that TransCanada PipeLines Limited is currently reviewing the various categories with a view to determining which wells would be eligible for a solution gas contract. In order to avoid gas wasteage by flaring, solution gas is given preferential market access. In view of current gas market limitations, failure to obtain access to a solution gas contract could mean deferral of a gas sales contract for some of the wells. The end result could be somewhat lower available gas production volumes than anticipated by either Westridge or Western Compression.

Notwithstanding some uncertainties respecting eligibility for sales gas contracts, the Board has no reservation in coming to the conclusion that conservation of the low-pressure oilfield gas should be commenced as soon as gas gathering systems and processing facilities are available. In this context a gathering system extending to all of the oil production facilities would have to be installed in a short time frame and a plant of adequate size to accommodate that raw gas would have to be built as soon as possible.

The Board believes that a plant of the size proposed by Western Compression would be adequate to accommodate the low-pressure oilfield gas and that proposed by Westridge would obviously be more than adequate. As well, however, construction of a plant that could process both oilfield gas and the gas cap gas as it becomes available would have economic and conservation advantages. All things considered, the Board believes that initial sizing of the plant is not a key question as modifications to this kind of relatively small sweet gas processing facility would be relatively simple and unobtrusive to make.

Area residents in the vicinity of the proposed Westridge plant site (the proposed location is about one-half mile north of Highway No. 11 and about 2 miles east of the village of Sylvan Lake), raised strong opposition to that plant site on the basis of potential impact on an area that they contended is essentially agricultural and small acreage holdings. As well they raised other issues most especially the one of potential safety risk of tanker trucks hauling liquified petroleum gas (LPG) (mainly propane and butane) from the plant onto Highway No. 11. Area residents in the vicinity of the proposed Western Compression site raised somewhat similar concerns but eventually withdrew their objections and indicated that they would be prepared to see both plants constructed provided that no duplication of gathering line facilities was approved by the Board.

Both Westridge and Western Compression acknowledged that their systems were to a considerable extent competing. However, Westridge contended that its project was much further advanced than that of Western Compression and filed evidence to demonstrate so. It had acquired the land and was pursuing the necessary re-zoning provision for the area on which it proposed to place its plant, submitted applications to the ERCB for the necessary gathering pipeline system, and was now surveying and had obtained easements to a significant portion of its required pipeline routes. Westridge therefore argued that its ability to meet a February 1986 plant start-up date was reasonably assured. Because of opposition from nearby residents to its plant, delays in obtaining the desired land re-zoning were being experienced but Westridge did not expect these to prevent plant construction and start-up as earlier scheduled. Area residents indicated at the conclusion of the hearing that they would continue to oppose re-zoning of the land for the proposed Westridge gas plant site.

Western Compression acknowledged that its proposals for gas gathering line routes were rather conceptual and that it had deliberately not pursued the acquisition of line routes and easements as it considered obtaining the ERCB gas plant approval (including the proposed site), the acquisition of gas plant processing components, and the commitment of gas producers to supply raw gas for that plant as of much higher priority on any critical time schedule. Its view was that if a plant

site was agreed to, it could rather readily (perhaps over a period of two weeks) obtain the land easements necessary for installation of its gathering system.

The Board agrees with area residents that it is in the interest of orderly development to not encourage installation of competing gas gathering facilities that would be duplicated in many of the areas to be served. It is evident that the Westridge program which includes obtaining ERCB gas gathering system approvals, of surveying, and acquiring easements for that system is underway. The Board does not share Western Compression's confidence about obtaining easements for a gathering system with very little time lapse especially bearing in mind this area's land use which is agricultural and small holding acreage development. The Board therefore believes that the acquisition of gathering system easements may be the critical factor in initiating gas conservation expeditiously.

Area residents in proximity to the proposed Westridge site contended that there is a relatively higher population density around this site which is comprised of a combination of small acreage residences and agricultural residences. Having in mind the variety of impacts including traffic, noise, and other such influences from this kind of gas plant, these area residents appealed for consideration of an alternative site with lower surrounding population density and on that basis implied that the Western Compression site would have some advantages. They drew particular attention to the potential safety risk of tanker trucks hauling LPG from the plant especially with regard to access onto Highway No. 11. These residents also contended that the use of gas-driven compressors at the plant would produce potential adverse noise impacts compared to the use of electric-driven compressors as proposed by Western Compression.

Although residents in the area of the Western Compression plant expressed considerable concerns respecting the use of Alberta Secondary Road (SR) 597 to move LPG by trucks travelling eastward to Highway No. 2, they subsequently withdrew that objection on the basis of undertakings by Western Compression that SR 597 may not be used and that any other concerns of local residents respecting movements of trucks from its plant onto Highway No. 20 or SR 597 would be resolved by direct consultation.

Westridge introduced expert testimony regarding traffic accident history at the two potential plant access routes and concluded that the truck access from the Western Compression plant onto Highway No. 20 would pose a significantly higher traffic risk than that from the Westridge plant onto Highway No. 11.

From the viewpoint of general impact on the region, the Board is satisfied that the Westridge proposed sweet gas plant is relatively small and would have only modest impact on surrounding residents not unlike that of other small industrial facilities including existing small sweet gas plants in the region. Respecting noise impacts, the Board agrees that the Westridge plant, since it proposes using gas-driven compressors, may occasionally create perceptible noise impacts. However, on the basis of the site visits to other plants in the region, the Board believes that such impacts would be very modest and seldom noticeable compared to other noise sources common to that setting. In addition, the Board notes that Westridge would be required to conform with compressor noise control requirements that are aimed at minimizing any such effects. Respecting traffic impacts there would obviously be noticeable traffic activity during the construction phase but subsequently the frequency of vehicular traffic into and out of the plant site would essentially be negligible in relation to current traffic patterns on Highway No. 11. However, the Board believes that the presence of tanker trucks on county roads, though of short duration daily, would be noticed by residents. Regarding the question of risk from tanker trucks entering a highway from a road having a lesser volume of traffic (plant or county for example), the Board believes that the truck operator's view and judgement as to the safest time to proceed is very important in avoiding accidents. In this respect, the Board notes that the truck driver proceeding onto Highway No. 11 from the county road would have a very clear view both east and west as he entered the highway. In this respect the driver would be in a very favourable position to avoid entry when high volumes of traffic were approaching and to determine the safest time to progress onto the highway. By comparison, tanker trucks from the Western Compression plant entering onto Highway No. 20 would appear to be presented with greater visibility problems. Overall the Board considers the risk factors in either case to be relatively low and probably much less than that which might be experienced in more congested traffic regions in surrounding towns and villages where similar products are presently being moved by tanker truck.

In view of the concerns raised by residents and having regard for the general objective of efficient and orderly development of oil and gas resources in this particular region lying between the western perimeter of Red Deer and eastern edges of Sylvan Lake, the Board believes that it is in the public interest to not encourage proliferation of gas plant sites as this would only exacerbate concerns of local residents respecting land use impacts. On that consideration, and the desire to avoid duplication of gathering line facilities on common areas of land, and having regard for the stage of completion of the two partially competing proposals for gas gathering, conservation, and processing, the Board concludes that it should grant only one of the applications and deny the other.

The Board believes that the Westridge project best meets the objectives of orderly, efficient, and economic conservation of oilfield gas. Recognizing the need for prompt installation of low-pressure gas conservation facilities, the Board approval of the Westridge application would be conditioned to require completion of construction within three months.

The Board is satisfied that conservation of low-pressure oilfield gas is economically viable. Therefore, in accordance with its normal practice, the Board will establish a gas conservation order requiring that all gas produced with oil in the areas in question be conserved on or after 1 March 1986.

Western Compression drew attention to the potential for excessive back pressures occurring in the proposed gathering line system owing to liquid build-up or other causes. The Board considers this an important matter since failure to provide measures in the design of the gathering system to preclude such occurrences could lead to periodic or sustained gas flaring at some batteries. This would lead to violations of the gas conservation order. The Board therefore would expect each producer, as well as Westridge, to evaluate this potential problem and to ensure that the gathering system is designed so as to ensure sustained gas conservation.

Therefore, the Board hereby is prepared to approve the Westridge application and denies Western Compression's application. The Board will grant the approval to Westridge subject to receipt of the necessary approval from the Minister of Environment with respect to environmental matters.

DATED at Calgary, Alberta, on 1 November 1985.

ENERGY RESOURCES CONSERVATION BOARD

N. Strom

N. Strom, P.Eng.
Board Member

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

M. J. Bruni
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Westridge Petroleum Corp. (Westridge) F. M. Saville, Q.C. R. A. Neufeld	J. K. Farries, P.Eng. B. R. Schlacter, P.Eng. (both of Westridge) L. M. Church, P.Eng. (of O'Rourke Engineering Ltd.) G. B. Unrau, P.Eng. (of Blue Range Resources Ltd.) G. E. Bohrson, P.Eng. (of Paloma Petroleum Ltd.) C. C. Hardy (of Sienna Resources Limited) H. A. Swanson, P.Eng. (of Swanson Transportation Consultants Ltd.)
Western Compression Systems Ltd. (Western Compression) C. G. Watkins	H. W. Higgins N. W. Plotke, P.Eng. (both of Western Compression) R. F. Cunningham, P.Eng. H. D. Hunter, P.Eng. P. E. McCombs (both of Audax Gas & Oil Ltd.) D. J. Cooke (of Don Cooke Land Service Ltd.) B. P. Dorin, P.Eng. (of American Eagle Petroleums Ltd.) G. C. Merritt, P.Eng. (of Pembina Resources Ltd.)
Residents Near Westridge K. G. Ruschin	T. Bradley J. Colbert E. Walters
G.N.E. Resources Ltd. S. Carscallan	
Dome Petroleum Limited L. L. Dolecki	D. Luft (of Dome Petroleum Limited)
Residents Near Western Compression D. Carlyle	D. Carlyle
Energy Resources Conservation Board staff H. R. Hansford M. Semchuck, C.E.T. M. T. Pittman	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

WESTHILL RESOURCES LTD.
SECTION 22, TOWNSHIP 54, RANGE 25,
WEST OF THE 4TH MERIDIAN
CAMPBELL-NAMAO CAMPBELL BLAIRMORE A POOL
CAMPBELL-NAMAO FIELD

Decision D 85-41
Application 850138

1 INTRODUCTION

1.1 Application

Westhill Resources Ltd. applied to the Energy Resources Conservation Board (the Board) for

- the termination of Order No. P 38,
- the concurrent production of oil and associated gas caps from the Campbell-Namao Campbell Blairmore A Pool (the A Pool), and
- the establishment of drilling spacing units (DSU) of one legal subdivision (Lsd) for the production of gas from the A Pool within section 22, township 54, range 25, west of the 4th meridian (section 22), with the target area being within the DSU and having sides 100 metres from and parallel to the sides of the DSU.

Additionally, Westhill proposed that the Board coalesce the Campbell-Namao Campbell Blairmore B Pool (the B Pool), located in the northeast quarter of section 22, with the A Pool.

The application was made under sections 74(1) and 26(1)(e) of the Oil and Gas Conservation Act (the Act) and section 4.030 of the Oil and Gas Conservation Regulations.

1.2 Interventions

Richard J. Churchill Ltd., the operator under Order No. P 38, appeared at the hearing in support of the application.

1.3 Hearing

The application was heard on 29 October 1985 at a public hearing held in Calgary, Alberta, before a Board panel comprising G. J. DeSorcy, P.Eng., L. A. Bellows, P.Eng., and J. R. Pow, P.Eng.

The Board rendered its decision orally at the conclusion of the hearing. This report outlines that decision and the basis on which it was made.

PARTICIPANTS AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Westhill Resources Ltd. (Westhill) S. R. Miller	J. K. Farries, P.Eng. W. J. Rodgers, P.Geol.
Richard J. Churchill Ltd. (Churchill) R. J. Churchill	R. J. Churchill
Energy Resources Conservation Board staff A. A. Gervais H. Abbink, P.Eng. K. Fisher A. R. Olive V. J. Vogt T. K. Wong, P.Geol.	

2 BACKGROUND TO ORDER NO. P 38

Order No. P 38 resulted from Application No. 7087 submitted in May 1973 by Churchill. Churchill requested that the 10 tracts in section 22 be operated as a unit for the production of gas from the Basal Quartz Formation through the well, RICHFIELD O.D. CAMPBELL NO. 1, located in Lsd 6 of section 22 (6-22 well). Churchill, using geological information available at the time, proposed that the allocation of production and costs to each tract be on a reserves basis rather than an area basis.

The Board heard the unopposed application on 25 October 1973, and issued Order No. P 38 on 17 December 1973.

3 CONSIDERATION OF THE APPLICATION

Westhill stated that it was proposing an optimum plan for recovering the remaining reserves in section 22 and other parts of the A Pool.

Westhill contended that according to its recent geological studies, the tract allocation factors prescribed under Order No. P 38 were no longer appropriate. It added that, among the mineral interest owners in section 22, only Churchill would be affected materially by the termination of the order.

Westhill pointed out that for many years concurrent production had been the prevalent producing method employed in the Campbell-Namao Field, despite the fact that it had never been formally approved by the Board. The applicant submitted that continued concurrent production would maximize the recovery of the remaining reserves.

Westhill maintained that the development of the many gas caps in section 22 would be optimized under one-Lsd (40-acre) spacing, this being the spacing available for oil production from that section. Westhill also noted a statement made by Churchill at the hearing which suggested that the 6-22 well, which is authorized to produce under Order No. P 38, recently recovered a small quantity of oil. Westhill added that if the Board were to redesignate the 6-22 well as an oil well, there would be no need for one-Lsd spacing for gas production in section 22.

Westhill maintained that its geological study indicated the A and B Pools to be one pool, and it requested the Board to redesignate the pool boundaries accordingly.

Westhill concluded that its proposal, if granted, would not impact negatively on mineral owners in either section 22 or the A and B Pools, but would provide them with an equitable opportunity to recover the remaining reserves.

Churchill supported the application, confirming that the applicant's proposal would provide for the efficient and orderly recovery of remaining reserves in section 22.

Churchill mentioned that over the past 3 or 4 months its 6-22 well had produced a small quantity of oil which had not been sold and, therefore, not yet reported to the Board.

4 DECISION

The Board accepts the evidence submitted by Westhill and notes that there were no objections to the application. Accordingly, the Board is prepared to

(a) terminate Order No. P 38 subject to the approval of the Lieutenant Governor in Council;

(b) issue an order to provide for the concurrent production of oil accumulations and associated gas caps in the Campbell-Namao Campbell Blairmore A Pool, as amended under item 4(d);

(c) conduct further investigation to determine whether the well, RICHFIELD O.D. CAMPBELL NO. 1, should be reclassified as an oil well; alternatively, if reclassification is not appropriate, the Board is prepared to authorize one legal subdivision as the drilling spacing unit for the production of gas from the

Campbell-Namao Campbell Blairmore A Pool in section 22, township 54, range 25, west of the 4th meridian, with a target area being within the drilling spacing unit and having sides 100 metres from and parallel to the sides of the drilling spacing unit; and

(d) amend the appropriate pool designation order to provide for the coalescence of the Campbell Blairmore B Pool with the Campbell Blairmore A Pool in the Campbell-Namao Field.

5 SUPPLEMENTARY BOARD DECISION

Subsequent to the hearing, the Board, upon investigation, found that the report of oil production at the well, RICHFIELD O.D. CAMPBELL NO. 1, could not be substantiated and, therefore, its reclassification to an oil well was not warranted. Therefore, the Board, bearing in mind there were no objections to the application, hereby approves one legal subdivision as the drilling spacing unit for the production of gas from the Campbell-Namao Campbell Blairmore A Pool in section 22, as set out in item 4(c) of this report, in order to provide an optimum opportunity for the recovery of the remaining reserves.

DATED at Calgary, Alberta, on 18 December 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Vice Chairman

L. A. Bellows, P.Eng.
Board Member

J. R. Pow, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DOME PETROLEUM LIMITED
COMMERCIAL OIL SANDS PROJECT AND
WATER DISPOSAL SCHEME
LINDBERGH SECTOR

Decision D 85-42
Applications 850428
and 850798

1 INTRODUCTION

1.1 The Applications

Dome Petroleum Limited (Dome), on behalf of itself and its partners, Sulpetro Limited and CNG Producing Company, filed Application 850428 pursuant to section 10 of the Oil Sands Conservation Act for approval of a commercial oil sands project. The proposed development would recover crude bitumen resources from the Cold Lake Oil Sands Deposit from an area of 101.5 sections of land in the Lindbergh Sector as shown on the attached figure. The commercial project would include existing and additional primary production operations and expansion of enhanced bitumen recovery (EBR) operations currently conducted on an experimental basis.

Primary production operations under the proposed commercial project would include the continued production of some 265 existing primary production wells located within the proposed commercial project area and the drilling and completion of approximately 150 new primary wells on the existing 16-hectare well spacing pattern. The new wells would provide additional information respecting the extent and quality of the crude bitumen reserves of the Mannville Group. All primary production of crude bitumen would be trucked to the central processing facilities in section 18, township 55, range 5, west of the 4th meridian (18-55-5 W4M).

Dome proposed the phased development of four and three quarter sections of land for cyclic steam operations involving 64 wells per section. These lands are section 30-55-5 W4M, sections 12 and 14-55-6 W4M, the south half and northwest quarter of section 10-56-6 W4M, and section 11-56-6 W4M. Sixteen wells for the EBR production operations would be drilled from a single drilling pad site located near the centre of each quarter section, using slant-hole drilling methods. Also included would be the construction of three new central processing, storage, and steam generation facilities that would be located in section 11-56-6 W4M, section 30-55-5 W4M, and section 12-55-6 W4M. The previously approved central processing facility to be located in the northeast quarter of section 10 would be shifted to the northwest quarter of section 11. This new location was chosen to accommodate the concerns of landowners and nearby residents.

In addition to the phased EBR development outlined above, Dome proposed to incorporate into its commercial project, already existing EBR experimental projects in section 18-55-5 W4M (Approval No. 3375), section 24-55-6 W4M (Approval No. 4012), and the northeast quarter of section 10-56-6 W4M (Approval No. 4448).

Fresh water for the project would be obtained from the Westmin Resources Limited system that obtains water from the North Saskatchewan River.

Dome filed supportive material respecting environmental impacts and mitigative measures, including applications to Alberta Environment for permits and licences under the Clean Air Act and the Clean Water Act. Also, it submitted documentation respecting impacts on agricultural land use, land conservation and reclamation procedures, and oily sand waste management. It further submitted some comparative costs regarding drilling pads located in the centre of a quarter section versus the edge of a quarter section.

Dome also filed Application 850798 for approval to initially dispose of a total of 9000 cubic metres (m^3) of water produced monthly in conjunction with sections 10 and 11 of the five-section cyclic steam stimulation project. The proposed water disposal scheme would involve injection into the Rex Sand Member through wells located in legal subdivision 9 of section 10 and legal subdivision 15 of section 11-56-6 W4M, and injection into the Cooking Lake Formation through wells located in legal subdivision 10 of section 10 and legal subdivision 11 of section 11-56-6 W4M.

1.2 The Interventions

Interventions expressing site-specific concerns and opposition to the project as proposed by Dome were filed by Mr. L. Miller, registered owner of the southeast quarter of section 10-56-6 W4M, the southwest quarter of section 11-56-6 W4M, and the southeast quarter of section 7-56-6 W4M and by Mr. C. Kozicky, registered owner of the southwest quarter of section 10-56-6 W4M. Although it did not oppose the application, the Elk Point Surface Rights Association (EPSRA) filed an intervention which expressed concerns related to agricultural land use impacts. Mr. A. Melnyk, residing on the northeast quarter of section 19-55-5 W4M, filed an intervention expressing concerns related primarily to air, noise, and nuisance impacts from the project.

The Town of Elk Point did not file an intervention. However, the Mayor, Mr. E. Buck, appeared at the hearing to voice the Town's support for the project.

Westmin Resources Limited intervened for the purposes of cross-examination and argument only.

Her Majesty the Queen in the Right of Alberta (the Crown) filed an intervention for the purpose of cross-examination and argument and to present a panel of witnesses to describe the role and activities of the Department of the Environment with respect to the applications. The panel provided information about environmental impact assessment, land reclamation, water resources administration, and licensing requirements that would have to be met under the Clean Air Act and Clean Water Act.

2 THE HEARING

A public hearing of the applications was held on 4, 5, and 6 November 1985 at Elk Point, Alberta before Board members N. A. Strom, P.Eng., L. A. Bellows, P.Eng., and Acting Board member T. F. Homeniuk, P.Eng. Those who appeared at the hearing are shown on the attached table.

3 PRELIMINARY MATTERS

Applications were made by Mr. L. Miller, Mr. C. Kozicky, and EPSRA to adjourn the hearing. These applications were made in writing to the Energy Resources Conservation Board (the Board) following the issuance of the Notice of Hearing and were spoken to by those parties at a meeting held in the Board's offices with the applicant on 21 October 1985, and at the opening of the hearing.

EPSRA, Mr. Miller, and Mr. Kozicky argued that due to the inclement weather, harvesting and other farming activities had been delayed into late fall and they were therefore unable to prepare for the hearing. Mr. Kozicky further indicated that in addition to his farming activities he held a second job.

Mr. Miller specifically argued that he had concerns with respect to the location and orientation of drilling pad sites and that an adjournment to 10 December 1985, at the earliest, might allow him, and those persons he hoped to retain to assist him, the opportunity to assess the application and to be in a position to fully participate in the hearing.

Mr. C. Kozicky indicated that he had a number of concerns with the project including water runs and winter construction. An adjournment to late November or early December would allow him the opportunity to be prepared.

EPSRA indicated that, although the Association was not objecting to the application, it required an adjournment of thirty days in order to be in the position to air some of its concerns at the hearing.

Mr. A. Melnyk, a local landowner and participant in the proceeding, indicated that he was prepared to proceed on the scheduled day or would be prepared to proceed on an adjourned day.

Westmin expressed its desire that the hearing proceed on 4 November 1985.

Alberta Environment took no position with respect to the adjournment requests and indicated that it would accommodate whatever decision was made by the Board with respect to an adjournment.

In response to the adjournment requests, Dome stated that all parties had been contacted through its public disclosure process and that the open-house held in May 1985 had been attended by Mr. Miller. He had been provided with a copy of the application at that time. Dome stated that if Mr. Kozicky did not obtain a copy of the application in May 1985, he was, in fact, provided with a copy by mail in August 1985. Dome further stated that it had made itself available since May 1985 to meet with landowners or groups of landowners to discuss any concerns they might have had with the application. Dome argued that these parties had had time to prepare and noted that, since the discussions with the Board on 21 October 1985, Mr. Miller had not taken any steps to be prepared should the hearing proceed on 4 November 1985.

In response to the argument that the interveners were in the process of conducting farming operations and were unable to attend, Dome expressed the view that, although it recognized that harvest operations had been delayed, current farming operations were not critical. Dome was prepared to accommodate local landowners through specialized sitting hours. Therefore, in its view, current farming operations were not a ground for adjournment.

Dome argued that if the hearing were adjourned timing might conflict with other Dome projects. Dome further argued that, if as a result of an adjournment construction were delayed to the following summer, those relying on this project may suffer.

The Board, after considering the positions of the parties, determined that sufficient notice and a reasonable opportunity had been provided to all participants to prepare for and participate in the hearing and therefore decided to proceed.

4 THE DECISION

At the conclusion of the hearing the Board announced its decision to grant Applications 850428 and 850798 which, subject to the authorization of the Lieutenant Governor in Council and the issuance of ministerial approvals respecting environmental matters and public lands and resources, would lead to issuance of Board approvals for the commercial oil sands project and the scheme to dispose of produced water. This report discusses the reasons for the Board's decision and the conditions of the Board approval.

5 REASONS FOR THE DECISION

5.1 Five-Section Thermal Recovery Project

5.1.1 Recovery Rates

Dome estimated that a typical well in the five-section thermal recovery lands would produce approximately 5 per cent of the bitumen in place (BIP) on primary recovery, and an incremental recovery of 10.6 per cent BIP on EBR. Each well would be subjected to steam stimulation and would produce approximately 12 000 m^3 of bitumen over a seven-year period. Dome testified that actual recovery could conceivably exceed 30 per cent BIP as a result of implementing a subsequent combination thermal drive (CTD) process such as that now being experimented on in section 18 and at its Morgan heavy oil project.

The Board recognizes that production performance of an oil sands in situ project is essentially an aggregate of the individual well-bore responses, each with its own sand-face characteristics. Primary production performance, which is obtainable at Lindbergh, along with well petrophysical data can provide a means to estimate cyclic steam stimulation response. The Board understands that Dome's forecasts are tied partly to such data, as well as rudimentary thermal model calculations. On that basis, the Board is prepared to accept at this time Dome's expectations of bitumen production rates and recovery levels of the five-section thermal project.

The Board recognizes that there is difficulty in projecting well production performance, due to limited data from cyclic steam experimental well tests in the Lindbergh area and the very limited reliance that would be placed on mathematical models without empirical performance input. The Board believes that verification of well performance predictions could be made following at least two cycles of steam injection and bitumen production. In this regard, the Board would condition an approval to require Dome to submit an updated assessment of the well-steaming strategy, well production performance, and expected recovery efficiency within a three-year period following issuance of an approval.

5.1.2 Sequence and Location of Surface Developments

Dome chose five sections of land which, in addition to the two sections already on EBR operations, it considered to be better in geological quality and, therefore, more likely to generate rapid production return and be financially self-sustaining from the outset.

Dome's plan calls for progressive development of the five sections over a five-year time span, starting with immediate commencement of pad construction and slant-hole drilling on sections 10 and 11-56-6 W4M this winter. Dome indicated that, while it could see some limited flexibility in the order of access to the identified sections, development of the sections and the construction and commissioning of

the central process facilities are linked together. Also of critical importance is the fact that financing of the project is tied to the sequence of land development as presented in the application. Any changes to this sequence might result in a review of the financial terms.

Respecting location of drilling pads for the development of each quarter section with slant-hole drilling, Dome stated that placing a pad in the centre of each quarter section is optimum from the viewpoint of installation and operating costs, access, security control for public safety, and nuisance impacts on local residents. It presented evidence showing the extra costs of half-size 8-well pads placed along the mid-point of quarter-section division lines. Dome submitted that the optimum location of pads is limited by the maximum deviation angle of wells and a maximum pipeline length from the central facility to pad site.

The Board agrees with Dome's general plan for phased development of the five sections identified, but notes that there is some room for flexibility in scheduling because development drilling occurs on one quarter section at a time. Also, the Board is generally satisfied with the design and location of the 16-well slant-hole pads and central processing facilities.

5.1.3 Soils

Alberta Environment testified that, from the viewpoint of soil management, it preferred to see top-soil stripping conducted prior to deep frost penetration. Dome submitted that it also preferred soil stripping prior to freeze-up and indicated that site preparations would be undertaken immediately following the receipt of the required Board and Development and Reclamation approvals. The Board agrees with Alberta Environment and Dome, and as well notes that the EPSRA has taken the same position at previous Board hearings. Timely issuance of approvals is therefore critical to optimum top-soil stripping, if construction is to occur this coming winter.

5.1.4 Groundwater

Dome was requested by Alberta Environment to obtain a litholog for a representative number of wells. Lithologs would provide a vertical rock profile between surface and bedrock, or about a 100 metre depth. They could be obtained through a collection of material cuts from the drilling fluid system at regular depth intervals. Lithology information could be obtained during drilling operations without causing any downtime.

The Board believes that an account of the general lithology in areas such as Lindbergh would assist landowners and the industry in identifying any communication between bitumen wells and potable water wells. It notes that Dome agreed to meet with Alberta Environment to devise a suitable logging program.

5.1.5 Powerlines

The Board is satisfied with Dome's general procedure to construct overhead powerlines on section and quarter-section division lines to central processing facilities, and underground lines to well pads on lands having the potential for cultivation, including hay and pasture lands.

5.1.6 Oily Sand Wastes

The applicant will store all oily sands and other entrained waste materials in a concrete-lined pit at the central processing facility site. A pilot project is currently underway to assess the feasibility of cleaning the produced oily sand by removing the bitumen and water. Should this technology prove successful, it will be added to the proposed central facility. At the same time Dome would be pursuing the development of disposal of cleaned sand in excavated pits designed for ultimate reclamation. In the interim, oily sand wastes would be disposed onto roadways. The Board accepts Dome's program.

5.1.7 Air Quality

A number of environmental issues were discussed by the applicant. A baseline air quality study was presented along with a discussion of anticipated impacts resulting from air emissions from the proposed project. The applicant concluded that the proposed project would have a negligible impact on existing air quality. All atmospheric emissions would be controlled in accordance with the Clean Air Licence issued for the project by Alberta Environment.

The Board accepts Dome's proposal to flare produced gases, monitor odours, follow-up on location should any odour complaints be made, and install incinerators if necessary. The Board finds the venting of casing gases at primary production wells to be acceptable provided that air quality standards are not exceeded.

5.1.8 Noise

Concerning the matter of noise, the applicant acknowledged the possibility that there might be noise impacts upon residents within the project area during the drilling phase. The applicant has initiated activity to improve the muffling of the primary noise sources from drilling and service rigs. In addition, the applicant undertook to respond to any public complaints concerning noise and, where the concerns expressed are valid, to employ appropriate mitigative measures. Following the commencement of operations, Dome proposed to monitor noise at those residences where predictive noise impact assessments had been made. The Board would require that Dome submit a report outlining the results of these noise surveys and to provide copies of the results to the affected landowners.

5.1.9 Impact on Residents

Mr. Melynk submitted that the quality of life in the area, as defined by air quality and noise levels, has declined due to increased development in the area. He was concerned about landowners, in a similar situation to his own, who are not directly involved with the project yet are exposed to these negative impacts.

The Board notes that part of Mr. Melnyk's concern is that the impact on the quality of life of some individuals would not be offset by some form of direct compensation. The Board is aware of Mr. Melnyk's concerns, however, matters of compensation are beyond the jurisdiction of the Board and Alberta Environment. A principal concern of regulatory agencies must be to minimize impacts by ensuring proper design, providing for monitoring and surveillance of operations, and by imposing regulation where necessary. The reduction or elimination of sources of the impacts at their point of origin serves to reduce to an acceptable level or to eliminate the negative impacts on the quality of life in a given area.

5.2 Confidentiality of Experimental Information

Dome requested that even though the section 18-55-5 W4M EBR operations will be incorporated into the proposed commercial project, the confidentiality of all operations and data be maintained. This request was made because it regarded the CTD process envisioned for section 18 as being of special proprietary value. The Board is satisfied that this request is reasonable and will continue to treat as confidential, individual well injection and production data and related experimental information from section 18 operations until 31 August 1986, or such other date as the Board might, upon application, set. However, the Board would release total production information of section 18 on a monthly basis.

5.3 Produced Water Recycling

Dome stated that it has no plans to process produced water for recycle because of a number of factors: (1) water production at Lindbergh contains unusually high total dissolved solids; (for example, it submitted comparative values showing Lindbergh water to contain an average of 60 000 milligrams per litre or about 10 times higher than at the Esso Cold Lake operation where over 90 per cent recycle is being achieved), (2) there is no commercially proven process that would permit reduction of that level of dissolved solids to an acceptable level for steam generator feedwater, with an acceptable degree of reliability; (3) the amount of fresh water needed for the five-section cyclic steam project, which will come from the North Saskatchewan River, is a relatively small amount and would represent only an average of 0.024 per cent of the mean annual flow.

Dome stated that it remained committed to on-going monitoring of new technology for treatment and reuse of produced water. Dome indicated

that its program would be more than just a literature search and that it would include direct contact with major water processing firms. It noted its participation in a recent AOSTRA/industry produced water treatment study and Environment Canada's research programs.

As a measure to help conserve fresh make-up water, Dome stated it would employ a proven water treatment system to minimize water waste in regeneration of softening media and backwashing of filter beds. Reduced fresh water consumption would be achieved by measures such as efficient mud solids control and reuse of drilling fluids at slant-hole well clusters. Where practical, drilling fluids would be moved from one pad to the next for reuse.

The Board accepts that the current state of the art indicates that reprocessing of Lindbergh produced water would be relatively expensive. However, because of expected increased fresh water make-up requirements for future EBR expansion plans, the Board regards the development of water recycle technology as especially important. In this respect the Board will require that Dome file an annual report reviewing the overall operational aspects of its water use system including chemical and physical properties and material balances for incoming and outgoing quantities, and a progress statement respecting Dome's programs for investigation and testing of produced water reprocessing technology.

5.4 Primary Production Well Development

In the 94.5 sections of land in which Dome plans delineation drilling, but for which no enhanced recovery activities are proposed at this time, Dome would use its geological information to identify priorities for drilling. About 150 additional wells would be drilled. Also, some 265 primary production wells already exist on those lands, all drilled vertically from individual well sites on 16-hectare well spacing.

The Board agrees that delineation drilling is necessary to further evaluate the resource base. Recognizing, however, that primary recovery from such wells would only be of the order of 2 to 5 per cent BIP in the 16-hectare well spacing unit, future infill drilling and EBR projects would be expected in many areas. With the objective of minimizing redundant surface disturbance, the Board believes that primary delineation wells should, wherever possible, be drilled from a location which would coincide with a future well pad site. This would probably mean that some delineation wells would have to be slant-hole drilled. Although this may incur some near-term, increased costs, the long-term advantages would probably include reduced land disturbances, reduction in land removed from agricultural use, reduction in the duplication of surface equipment, more efficient, safe, and environmentally suitable operation, and reduced road traffic.

The Board realizes that the number and specific location of primary wells would depend on the ongoing results of the delineation drilling program. However, the Board would require Dome to address the matter of

surface locations and conform to a well pad concept when it applies for each well licence or group of well licences. If well locations are not shown to be situated on potential future well pads, Dome would be required to provide environmental and technical reasons for its proposals.

Primary wells would initially be operated under low temperature, low stress conditions. However, wherever future EBR activities occur, they would likely involve high temperature operations and severe thermal stresses. Because it is not possible to identify those areas in advance, the Board would require that casing and cementing programs for all future primary wells be designed to withstand the anticipated thermal effects.

5.5 Planning and Authorization

5.5.1 Project Production Rate

Dome supplied a 12-year forecast of rates of bitumen production from the applied-for EBR and primary project lands. Production rates were shown to gradually increase to a peak rate of some 3300 m^3/d in 1989, and gradually decline to about 500 m^3/d in 1996. Dome emphasized that it would be investigating further EBR methods which it may wish to use in these lands.

Dome said it would be pursuing the possibility of incorporating an additional 21 sections of land in the area in which it holds joint interest. Any such expansion of activities would, however, be subject to Board approval. Resulting production rates would be additive to those described in the current application.

To foster orderly development and environmental control, an upper level of production expected from the project would be inserted as a condition of the approval. This would provide a "benchmark" beyond which further review and consideration could be given to the broad implications of the project and its inter-relation with other activities locally, within the province, and the energy industry generally. To provide some flexibility the Board would assign an initial limit of 4000 m^3/d of crude bitumen determined on an annual basis.

5.5.2 Construction, Implementation, and Termination

Respecting the term of approval, the Board would specify an expiry date of 31 December 2006. The Board would require, as a condition of the approval, that Dome submit a construction and site development report on a semi-annual basis. The report would provide a summary of primary production delineation drilling and progress on the drilling, construction, and commissioning of the five-section EBR project. A development plan for the ensuing years would be required on an annual basis. The Board would assess the progress of the overall scheme development in relation to the original objectives and may initiate changes to certain terms of the approval to reflect any impacts of revised schedules.

5.5.3 Lindbergh Area Planning

The Board believes that the application put forward by Dome provides an opportunity for long-range planning which would be beneficial to all landowners and occupants in the area including the agricultural and petroleum industries. Dome identified an additional 21 sections, interspersed throughout the applied-for 101.5-section area, as other properties in which Dome holds a joint interest. Dome emphasized that considerable discussion, planning, and negotiation, which would probably begin in the next six months, would be required before any proposal to develop Dome/Joint Operator EBR schemes in those lands could be put forth.

Dome pointed out that varying resource ownership and varying resource delineation and development plans by the different mineral lease owners inhibits well co-ordinated and efficient development at Lindbergh. In response to the Board's concern respecting the proliferation of production facilities, Dome suggested that as many as four to six sections of land might be served by one central processing facility. However, technical limitations, especially entrained sand, would likely prevent pipelining the produced bitumen any further. The Board views a four to six-section spacing for central facilities as an improvement over current operations and would ask that Dome pursue achievement of that objective in co-operation with other operators in the area, and endeavour to incorporate suggestions from landowners and occupants.

6 WATER DISPOSAL

Dome proposed to dispose of water produced in conjunction with the production of crude bitumen from sections 10 and 11 by injection of equal volumes of fluid into the Rex Member and Cooking Lake Formation. Dome stated that it intends to pursue the feasibility of injecting all of the produced water into the deeper Cooking Lake Formation once the proposed disposal wells have been deepened and it has had the opportunity to test the actual injectivity and capacity of the formation.

Dome committed to providing the Board with a detailed analysis of the ultimate disposal capacity of both proposed disposal zones. To ensure the integrity of the disposal wells, Dome would case and equip the disposal wells in accordance with ERCB requirements and regulations, confirm the quality of the cement job on the outer string of casing in each well prior to the initiation of disposal operations, conduct daily checks on the injection and casing-tubing annulus pressures for each well, and conduct yearly pressure fall-off surveys on each disposal zone to determine the existence and magnitude of any pressure build up.

Having regard for the commitments made by Dome and the conditions that would be included in the approval, the Board is satisfied with Dome's proposed method of water disposal.

7 SUMMARY

The Board decided to grant Applications 850428 and 850798 at the conclusion of the hearing. The main reasons for its decision and conditions of its approval, shown in draft form in the appendix, are summarized as follows:

- Phased development of the four and three quarter sections of new thermal projects is acceptable.

- Verification of performance and recovery predictions is to be made within three years of the approval of the project.

- The design and location of well pads and central processing facilities are technically and environmentally satisfactory and are generally acceptable in relation to land use impacts.

- Top-soil stripping should be carried out prior to freeze up wherever possible.

- Dome's proposal to install underground powerlines in certain locations to minimize impacts on agricultural operations is acceptable.

- Atmospheric and noise emissions from the project are to be suitably monitored and mitigated in accordance with regulations administered by the Board and Alberta Environment.

- Licence applications for future wells must conform to the pad concept or provide reasons for any divergence.

- Confidentiality for operations in section 18-55-5 W4M, with the exception of total production on a monthly basis, will be maintained.

- Having regard for the high dissolved solids content of the produced water; the current status of water treatment technolgy, and contingent on the development and maintenance of acceptable water disposal capacity, Dome's proposal not to treat produced water for recycle is accepted. However, Dome is expected to diligently investigate potential produced water reprocessing technology and provide progress reports to the Board.

- An annual production limit of 1 460 000 m^3 (equivalent to 4000 m^3/d) of crude bitumen will be established to provide an optimum level of control and flexibility for the operation of the project.

- A project life of 20 years is appropriate, based on the establishment of a series of construction and performance review check points in the approval.

- Dome, in co-operation with other operators, and including suggestions from landowners and occupants, will be expected to pursue the goal of a four to six-section spacing of central facilities in the general Lindbergh area.

Subject to the receipt of the necessary Order in Council and Ministerial Approvals, approvals for the project and the water disposal scheme will be issued.

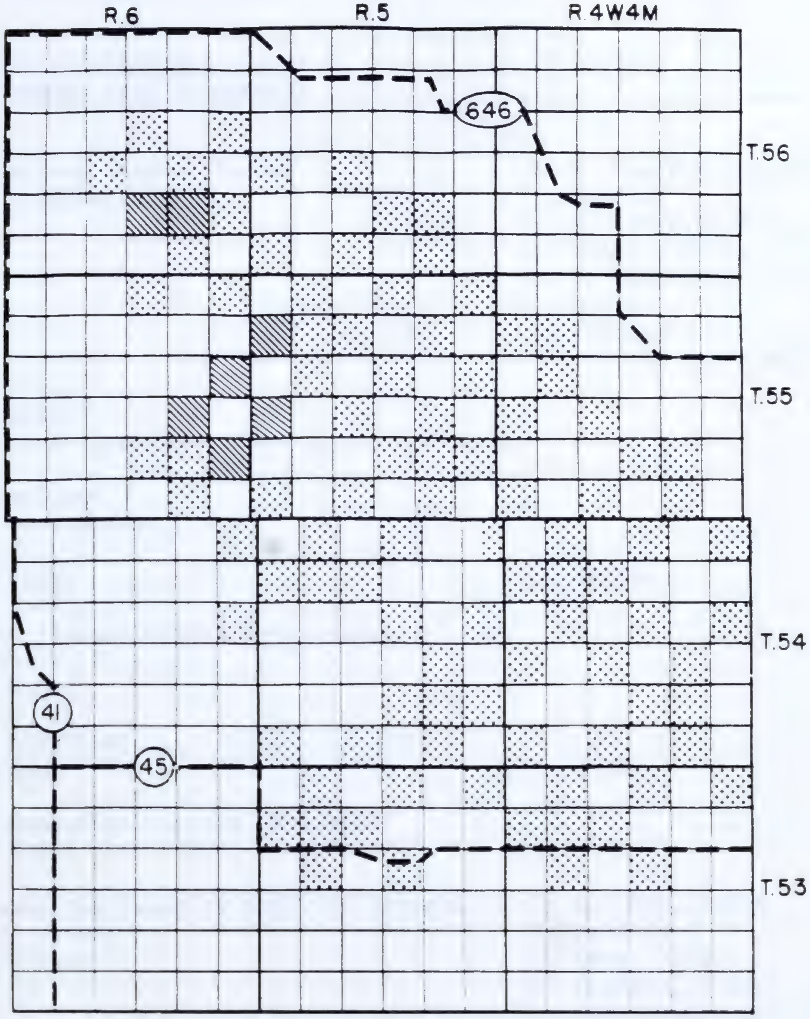
DATED at Calgary, Alberta, on 15 November 1985.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Board Member

L. A. Bellows, P.Eng.
Board Member

T. F. Homeniuk, P.Eng.
Acting Board Member



PROPOSED PRIMARY DEVELOPMENT AREAS

EXISTING AND PROPOSED THERMAL DEVELOPMENT AREAS

DOME PETROLEUM LIMITED
LINDBERGH COMMERCIAL OIL SANDS PROJECT
APPLICATION NO. 850428

D85-42

ERCB

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Dome Petroleum Limited (Dome) A. L. McLarty	R. M. Scarborough, P.Eng. S. Hoffman B. R. Croft, P.Eng. A. Hanert, P.Eng. R. J. Hempstock, P.Eng. T. Drury A. Reimer, P.Ag. of Jim Lore and Associates Ltd.
Mr. L. Miller* B. K. O'Ferrall	
Mr. C. Kozicky* P. T. Johnston	
Mr. A. Melnyk	A. Melnyk
Elk Point Surface Rights Association (EPSRA)** A. Bugej	
Town of Elk Point E. Buck	E. Buck
Westmin Resources Limited (Westmin) S. Sills	
Her Majesty the Queen in Right of Alberta (the Crown) A. Watson	J. C. Lack, P.Eng. F. Schulte J. King, P.Ag. V. Carlson, P.Geol, all of the Department of the Environment
Energy Resources Conservation Board staff H. R. Hansford J. R. Nichol, P.Eng. I. M. Cameron, P.Eng. M. MacRae I. Weleschuk, P.Ag.	

* Messrs Miller and Kozicky did not appear at the hearing and their counsels, B.K. O'Ferrall and P. T. Johnston respectively, only appeared for the opening and preliminary portion of the hearing.

** Mr. A. Bugej similarly appeared only during the opening and preliminary portions, and withdrew the intervention of EPSRA.

*DRAFT FORM OF APPROVAL

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Dome Petroleum Limited for the recovery of crude bitumen from the Cold Lake Oil Sands Deposit in the Lindbergh Sector.

APPROVAL NO. 4746

WHEREAS the Energy Resources Conservation Board, by Approvals No. 3375, 4012 and 4448, approved experimental schemes of Dome Petroleum Limited, for the recovery of crude bitumen; and

WHEREAS the Board is prepared to grant an application by Dome Petroleum Limited, for a commercial oil sands scheme subject to the terms and conditions herein contained; and

WHEREAS the Board deems it desirable to revise and consolidate Approvals No. 3375, 4012 and 4448.

WHEREAS the Minister of the Environment has given his approval, hereto attached, insofar as the application affects

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* This is only a form of approval. The approval, when issued may have minor variations from that set out here.

matters of the environment, and the Associate Minister of Public Lands and Wildlife has given his approval, hereto attached, insofar as the application affects land and resources that are the property of the Crown in the right of Alberta; and

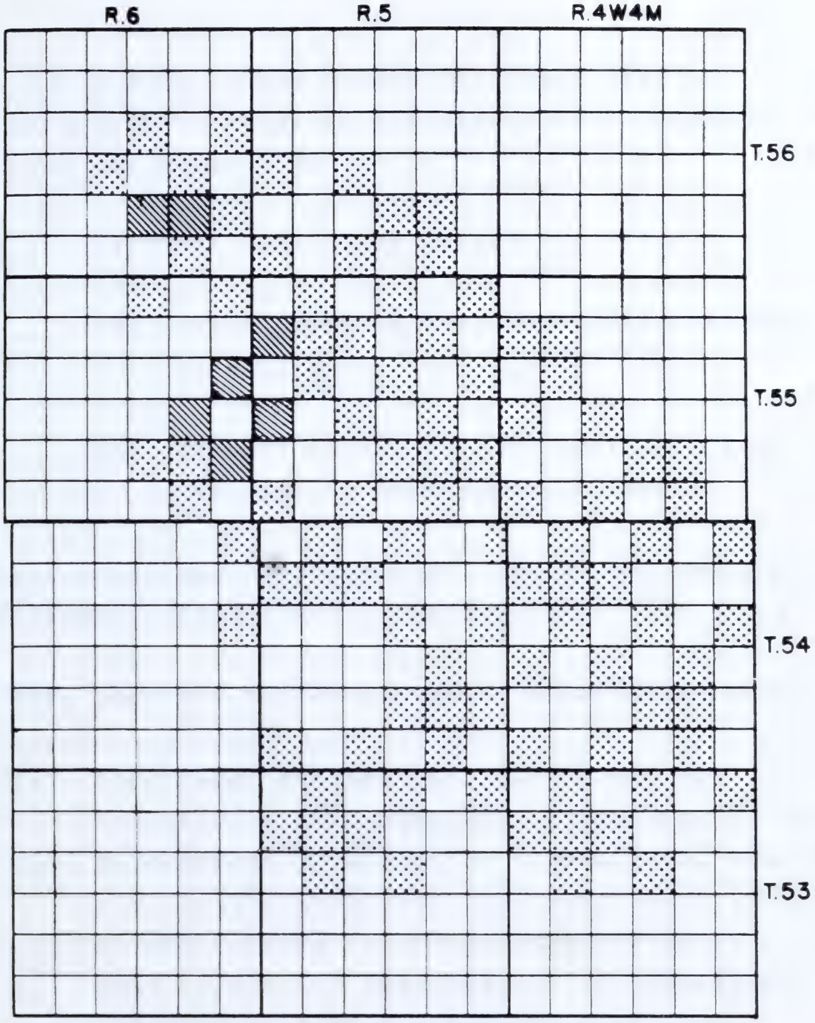
WHEREAS the Lieutenant Governor in Council, by Order in Council number O.C.________and dated__________, has

authorized the granting of the approval subject to certain conditions set out in the Order in Council; and

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil Sands Conservation Act, being chapter O-5.5 of the Statutes of Alberta, 1983, hereby orders as follows:

1. (1) The scheme of Dome Petroleum Limited (hereinafter called "the Operator") for the recovery of crude bitumen from the Cold Lake Oil Sands Deposit in the area outlined on the attachment to this approval, marked Appendix A, as such scheme is described in Application No. 850428 dated 22 April 1985 and addenda thereto dated 31 July, 16 September and 24 October 1985 and in evidence and exhibits given at the hearing of the application, is approved, subject to the terms and conditions herein contained.

(2) The Operator shall notify the Board of any proposed alteration, or modification to the scheme or to any equipment proposed for use therein, prior to effecting the alteration, or modification.



COLD LAKE OIL SANDS DEPOSIT

ERCB

APPENDIX A TO APPROVAL NO. 4746

REFERENCE

PRIMARY DEVELOPMENT AREAS

THERMAL DEVELOPMENT AREAS

D 85-42

ERCB

(3) Where, in the opinion of the Board, any alteration or modification of the scheme or to any equipment proposed for use therein is

(a) not of a minor nature,

(b) not compatible with the scheme approved herein, or

(c) may not result in an improved or more efficient scheme or operation,

the alteration or modification shall not be proceeded with or effected without the further authorization of the Board.

2. This approval is for a project which will include:

(a) the phased development of cyclic steam stimulation in Section 30 of Township 55, Range 5, Sections 12 and 14 of Township 55, Range 6, the North-west quarter and South half of Section 10 and Section 11 of Township 56, Range 6, all West of the 4th Meridian for the recovery of crude bitumen from the Cummings Member,

(b) 265 existing primary production wells located within the commercial project area as listed in Application No. 850428,

(c) the drilling of 150 new primary production wells on 16-hectare well spacing for the recovery of crude bitumen from the Mannville Group,

(d) the incorporation of existing wells and operations covered formerly by experimental approvals for Section 18 of Township 55, Range 5, (Approval No. 3375), Section 24 of Township 55, Range 6, (Approval No. 4012) and the North-east quarter of Section 10, Township 56, Range 6 (Approval No. 4448), all West of the 4th Meridian, and

(e) the provision of confidential information status until 31 August 1986 in Section 18 of Township 55, Range 5, West of the 4th Meridian, with the exception of total monthly production data for that section.

3. (1) This approval is for the production of crude bitumen of a maximum of 4000 cubic metres per day on an annual average basis.

(2) The Operator shall make application to the Board for future phases of the scheme, or for any changes to the scheme that would cause crude bitumen production to exceed that specified in subclause (1).

4. The Operator shall conduct all operations to the satisfaction of the Board and in a manner that, under normal operating conditions, will ensure

(a) the recovery from the oil sands deposit of the practical maximum of crude bitumen,

(b) the gathering and utilization of the practical maximum amount of gas produced, including casing vent gases, and

(c) the avoidance of waste of liquid or gaseous hydrocarbons, and

(d) the efficient transportation of crude bitumen to market.

5. (1) The Operator shall measure and record, to the satisfaction of the Board, the volumes and other pertinent characteristics of all fluids injected and produced and other streams as may be required by the Board.

(2) The measurements referred to in subclause (1) shall be made with sufficient frequency and accuracy as to allow a calculation, to the satisfaction of the Board, of mass balances, energy balances and recovery efficiencies of the production processes.

6. The Operator shall, prior to 31 December 1988, submit to the Board updated projections of cyclic steam well performance based on a minimum of two complete cycles of steam injection and crude bitumen production from all eligible wells within the project to verify or change rate-time performance predictions filed in Application No. 850428.

7. Following the commencement of operations the operator shall conduct a noise survey at locations for which predictive noise assessment was conducted by the operator prior to project construction and submit the results of all

monitoring to the Board and to the directly affected landowners or occupants thereof.

8. Following the commencement of operations, the operator shall submit to the Board an annual report of the overall operational aspects of its water use system including chemical and physical properties and material balances of incoming and outgoing water quantities and a description of programs being pursued in the investigation and testing of produced water processing technology, this report to be filed no later than 1 March of the following calendar year.

9. The Operator shall, commencing 30 September 1986, submit a report to the Board, by 30 September of each year, showing the proposed development plan for the next calendar year.

10. During construction of the project facilities and drilling of the project wells, the Operator shall semi-annually report the progress of construction and site development to the Board.

11. (1) The Operator shall log all wells from total depth to surface by means of a spontaneous potential-resistivity or gamma ray-resistivity type logging device and other such devices as may be required to ensure sufficient depth and directional control.

(2) The Operator, shall core the Cummings Member in at least one well per quarter section in thermal recovery project areas and the core shall be analyzed and the clean cut surface of the slabbed core shall be photographed.

12. The Operator shall submit to the Board an annual reserves update including appropriate supporting maps showing the volume of crude bitumen and gas in place in any oil sands zones identified by wells drilled to total depth during the previous calendar year, those reports to be filed no later than 1 March.

13. (1) Following the commencement of steam injection or crude bitumen production operations, the Operator shall file with the Board, on forms provided by or satisfactory to the Board,

(a) monthly hydrocarbon and water balance reports for

(i) the production facilities,

(ii) any water treatment facilities, and

(iii) the overall project,

(b) a performance evaluation report summarizing all activities and operations carried out, including

(i) hydrocarbon and water balances over the report period, in a format similar to that required monthly by subclause (1) paragraph (a)

(ii) energy balances over the report period of the overall project,

(iii) a discussion of any unique drilling, completion, production or injection problems encountered at specific wells,

(iv) details of any major operating incidents,

(v) a review of any operations conducted to reclaim or dispose of sand and oily waste generated by the project,

(vi) an assessment of the efficiency of injection and production operations,

(vii) a review of operations conducted to minimize the make-up water requirements, and

(viii) such other information as the Board from time to time may require.

(2) The reports required by subclause (1), paragraph (a) shall be filed by the 15th day of the month following that month for which the balances are being reported.

(3) Four copies of the reports required by subclause (1), paragraph (b) shall be submitted semi-annually for the first 5 years for operating periods ending 30 June and 31 December, and annually thereafter, and shall be filed within 60 days of the expiration of the report period.

14. The Operator shall take such steps and effect such measures as may be necessary in the completing and operation of wells to prevent production casing failures.

15. The Operator shall dispose of produced sand in an environmentally safe manner satisfactory to the Board.

16. The Operator shall, not later than 1 December 1986, submit to the Board, spill contingency plans for the scheme in the detail specified in the Board's Interim Directive No. ID-OG-PL 75-1.

17. (1) If crude bitumen, salt water or other liquid other than fresh water is spilled from any equipment or facility associated withe scheme, the Operator shall take immediate steps to contain and clean up the spill.

(2) Where a spill occurs from a facility described in subclause (1), and

(a) the liquid is not confined to the site of the facility from which the spill occurred, or

(b) the volume of liquid spilled is in excess of 2 cubic metres,

the Operator shall immediately report the size and location of the spill to the Board.

(3) When so directed by the Board, a report made pursuant to subclause (2) shall, within 2 weeks of the date of the spill, be confirmed in a

written report to the Board and be supplemented with at least the following additional information:

(a) the time the spill occurred,

(b) a description of the circumstances leading to the spill,

(c) a discussion of actions taken in response to the spill,

(d) a discussion of steps to be taken to prevent similar future spills, and

(e) an outline and schedule for the spill site rehabilitation program.

18. (1) Attached hereto as Appendix B to this approval is the order of the Lieutenant Governor in Council authorizing the granting of the approval.

(2) This approval is subject to the terms and conditions prescribed by the order of the Lieutenant Governor in Council set out in Appendix B.

19. This approval, insofar as it pertains to matters of the environment, is subject to the approval of the Minister of the Environment, hereto attached as Appendix C to this approval, and insofar as it pertains to matters that affect land and resources that are the property of the Crown in the right of Alberta, is subject to the approval of the Associate Minister of Public Lands and Wildlife, hereto attached as

Appendix D to this approval, and to the terms and conditions therein contained.

20. (1) The Board may,

(a) upon its own motion, or

(b) upon the application of an interested person,

rescind or amend this approval at any time if, in the opinion of the Board, circumstances so warrant.

(2) This approval, unless rescinded before that date, expires on 31 December 2006 unless upon application by the Operator a later date is approved by the Board.

21. Board Approvals No. 3375, 4012 and 4448 are rescinded.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

NOVA, AN ALBERTA CORPORATION
APPLICATION TO CONSTRUCT A GAS
PIPELINE IN THE DUHAMEL AREA

Decision D 85-43
Application 851082

1 THE APPLICATION

NOVA, AN ALBERTA CORPORATION (NOVA) proposes to construct approximately 7.71 kilometres (km) of 168.3-millimetre outside-diameter pipeline and related facilities to loop its existing pipeline, constructed in 1981, from a point in legal subdivision 5 of section 31, township 45, range 20, west of the 4th meridian (Lsd 5-31-45-20 W4M), to a tie-in point in Lsd 7-29-45-21 W4M, as shown on the attached figure.

2 THE INTERVENTIONS

The Board received an intervention from Mr. Alan G. Wilson and Mrs. Jessie Wilson (the Wilsons) of RR #2, New Norway. The Wilsons objected to the proposed loop on the grounds that it was not the best route and that a more logical route was to parallel an existing oil pipeline to the north of the hamlet of Duhamel. The Wilsons claimed that NOVA had not fulfilled its commitments to the Board and to themselves in respect of reclamation on the original (1981) pipeline route.

The Board also received a letter of intent to appear at the hearing from Mr. Ralph Tate of New Norway.

3 THE HEARING

The application was considered at a public hearing in Camrose, Alberta, on 7 November 1985, with G. J. DeSorcy, P.Eng., C. J. Goodman, P.Eng., and E. G. Fox, P.Eng., sitting. Participants at the hearing are shown in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
NOVA, AN ALBERTA CORPORATION (NOVA) H. D. Williamson	B. Lee, P.Eng. W. Litvinchuk, P.Eng. G. Houston, P.Eng. R. Seager M. McCall
Mr. Alan and Mrs. Jessie Wilson (the Wilsons) W. A. Andreassen	F. Fenger A. G. Wilson
R. Tate*	
Alberta Environment staff D. L. Bratton, P.Eng.	
Energy Resources Conservation Board staff A. A. Gervais A. Cassley, P.Eng. R. Komesch	

* Mr. Tate appeared for cross-examination purposes only.

4 PRELIMINARY MATTER

The applicant and the intervener made references to evidence which was considered at a hearing held in Camrose on 6 August 1981 to consider the application for the pipeline which NOVA now proposes to loop. The Board points out that it cannot review the evidence given with respect to that application, and the application before it must be judged on the evidence provided to it at the hearing on 7 November 1985.

5 THE ISSUES

The Board considers that the issues related to this application are

- the need for the pipeline,
- the economic and orderly development of pipeline facilities, and
- route selection and environmental impacts.

6 VIEWS OF NOVA

NOVA stated that it had recognized in 1984 that the pipeline system in the Ohaton-Ferintosh area was becoming restricted and had initiated discussions with shippers in the area. Following the discussions, NOVA commissioned a deliverability study for the area. From the study and a consideration of sales requirements, NOVA perceived the need for the applied-for facilities to ensure that contracted volumes could be transported according to transportation contracts with shippers in the area. NOVA estimated that, if the applied-for facilities are not installed this winter, volumes through this part of the system would be restricted to about 45 per cent of contracted volumes. It pointed out that the demand is heaviest during the winter months and, should gas not be available, the shippers would not be able to honour contractual commitments, and therefore there is an urgent need for the applied-for facilities.

With respect to route selection, NOVA recalled that at the 1981 hearing it was shown that there were no significant advantages to the northern route which is being proposed again by Mr. Wilson (see attached figure). For the purposes of this application, NOVA had made only a cursory examination of the northern route. It has learned, however, that the Gulf Canada pipeline to the north of Duhamel had been out of service for 6 or 7 years and that the right of way was completely rehabilitated. NOVA's route selection team had visited the site of its existing pipeline to determine if there had been any significant change to routing factors, and had considered the proposed realignment of Highway 21.

NOVA determined that there were significant reasons why the proposed pipeline should parallel its existing pipeline. It proposed to take an additional 10 metres (m) of right of way on the south side of the existing right of way and locate the pipeline approximately 9 m south of the existing pipeline. For the northern route, NOVA pointed out that where the proposed line would parallel the Gulf Canada line it could perhaps use 7 m of working space on the Gulf right of way, but would require an additional 13 m of new right of way. Where the proposed line deviated from the Gulf Canada line, a right of way width of 18 m would be required.

NOVA therefore believed that the applied-for route used land more efficiently than the northern route, and claimed that it also permitted greater flexibility of operation and more efficient line surveillance.

NOVA stated that the costs of the northern route could be 6 to 8 per cent greater than the applied-for route based primarily on a length comparison, the applied-for route length being 7.7 km and the northern route approximately 8.2 km. NOVA gave a breakdown of costs as approximately 40 per cent on construction, 40 per cent on materials, 10 per cent on land and reclamation, and 10 per cent on engineering.

It indicated that the total capital cost of $631 600 included the cost of the extra depth and pipe wall thickness at the proposed highway realignment and approximately $1500 for each crossing of a municipal road. The capital cost also included reclamation work up to the point of final clean-up by the contractor.

NOVA explained that the site of the connection into its system at the west end was chosen because if it were any farther north and if the producer's plant had a malfunction, there is a possibility that sour gas would enter the NOVA system.

NOVA stated that its proposed construction at the site of the realignment of Highway 21 had been extensively discussed with and the design ultimately approved by Alberta Transportation.

NOVA proposed a construction procedure in which topsoil would be stripped from the ditch line only, a width of about 1 m, using its frozen-topsoil-stripping machine. The topsoil would be stored on the working side of the right of way. Pipe sections could be strung immediately adjacent to the topsoil pile. The greater part of the ditch would be excavated by a bucket-wheel ditcher and the soil piled on the opposite side of the ditch. When the pipes have been welded together, the joints would be coated and the pipe coating electronically inspected before the pipe is lowered into the ditch. The excavated subsoil would then be replaced, but the topsoil would not be replaced until after the spring thaw to allow for any ditch subsidence prior to its replacement. A grader wheel or bulldozer track would be used to compact the subsoil prior to replacing the topsoil. A weed control program would be undertaken as required. All areas disturbed during the construction would be cultivated to prepare a suitable seed bed. Landowners would be consulted about the revegetation of pastureland. NOVA did not anticipate any difficulties in crossing the Wilsons' private drainage ditch and indicated its preparedness to fence the immediate seasonal drainage area as it had done during 1981 construction at Mr. Wilson's request.

NOVA pointed out that it would employ a full-time environmental field co-ordinator responsible for ensuring that its environmental policies and procedures are carried out, whereas in 1981 a co-ordinator had been on site only on a part-time basis. A topsoil stripping inspector will also be on site on a full-time basis to ensure that the contractor follows topsoil stripping specifications.

NOVA admitted that there is a problem with Mayweed (scentless chamomile) on a portion of Mr. Wilson's land but stated that it did not know the source of the weed. It has been hand-picking and burning the weed and is gaining control over it.

NOVA was of the opinion that most of the problems it had encountered on Mr. Wilson's land were due to the topsoil-stripping technique used in 1981, namely the "rotovating" of the right of way which destroyed the sod layer, prolonging the reclamation period. For the proposed construction NOVA expressed confidence that its newer technique is an improvement over the rotovating technique.

7 VIEWS OF THE WILSONS

Mr. Fenger related his experience of land negotiations with NOVA representatives in support of the Wilsons' belief that NOVA considered the applied-for pipeline and the Ohaton to Duhamel meter station pipeline as a single project.

Mr. Wilson, in describing the land which NOVA proposes to cross, pointed out that the applied-for route was in close proximity to a number of farmsteads and that the pipeline constructed in 1981 had many bends, partly to avoid a very wet area in section 27-45-21 W4M (Sec 27-45-21 W4M). Mr. Wilson explained that Sec 27 is a low-drainage area for a watershed and drains water from Secs 28, 34, and 35. He pointed out that he has a private drainage ditch which starts south of the quarter line in Sec 27 and carries water north through Sec 34, across the highway and railway, and eventually drains into the Battle River. Mr. Wilson estimated that in flood conditions approximately 180 acres of Sec 27 is under water.

Mr. Wilson contended that the proposed realignment of Highway 21 rendered a 53-acre portion in the northeast quarter of section 27 (NE 1/4 Sec 27) of little use for agricultural purposes. The realignment would divide the affected land into four parcels of which the existing NOVA pipeline encumbered three. Another pipeline would encumber more land. Mr. Wilson doubted whether anyone would purchase the lands for agricultural purposes, but the affected land could probably be used for acreage development, although he had no immediate plans for subdivision and the land was still zoned for agricultural purposes.

Mr. Wilson produced evidence to show that Alberta Transportation had firm plans to realign the highway and he believed it had valued the land as acreage land.

Mr. Wilson stated that all of Sec 26, and Sec 27 west of the highway to the quarter line, plus a pasture area, is grassland and that NOVA would be crossing about 0.4 mile (0.6 km) more grassland than it did in 1981. He contrasted this topography with that of his proposed northern route, showing that the northern route was almost all cultivated land, with the occasional acreage and a narrow strip of subdivided land north of Duhamel. The northern route was also farther away from farmhouses and acreages than the applied-for route.

Mr. Wilson explained that when a pipeline is constructed through grassland there is inevitably some sinkage along the ditch line which can only be filled by importing topsoil, whereas on cultivated land the working of the land tended to smooth out sinkage. Mr. Wilson believed this to be an important advantage to the northern route, particularly in view of the problems which NOVA had in reclaiming the 1981 right of way across the grassland.

Mr. Wilson pointed out that on the nortnern route there were fewer municipal roads to cross and only one highway crossing on a straight part of the highway. The crossing point of his private ditch would be at a point where the drainage gradient was much better than on the applied-for route where it was essentially flat.

Mr. Wilson referred to contractual commitments contained in the right of way agreement for the 1981 construction and commitments made in the 1981 Board decision report. He claimed that NOVA had not fulfilled all the commitments and produced photographs to support the claim. Mr. Wilson also described the prolonged attempts at reclamation made by a variety of NOVA crews or contractors and the work which he himself had done.

Mr. Wilson was particularly concerned about the introduction of Mayweed onto his property and stated that NOVA had acted to control the weed only after a weed control order was filed by the County of Camrose. Mr. Wilson was of the view that the weed was introduced in the topsoil which NOVA had imported for reclamation purposes. He pointed out that he had offered to remove a fence on his land to allow NOVA access to drifted soil at the fence line which had no weeds, and that NOVA had declined the offer.

Another concern of Mr. Wilson was the proposal by NOVA to leave the topsoil out of the ditch until the following spring. Mr. Wilson stated that he ran cattle in the pastureland and wondered how he could operate the farm with the ditch open and topsoil piled across the heart of his farm.

8 VIEWS OF THE BOARD

The Board is satisfied that there is a need for the applied-for pipeline facilities, and that the design of facilities satisfies all requirements under the Pipeline Act.

The Board has compared the costs of the applied-for route with the northern route proposed by Mr. Wilson insofar as it is able to do so from the evidence submitted. Taking into account that the northern route would be lengthier, but would be on different terrain, would have only one versus two highway crossings, one less municipal road crossing, and less reclamation, the Board estimates the northern route

would be of the order of 5 to 6 per cent more expensive than the applied-for route. This might amount to some $35 000 which is significant, but not sufficiently so to override other comparative factors.

By an inspection of the photomosaic submitted by NOVA and from NOVA's testimony, the Board accepts that the right of way followed by the Gulf Canada line is fully reclaimed. The pipeline in that right of way is an abandoned line and the Board has no knowledge of any plans for further use by Gulf Canada (or Petro-Canada) of the right of way. From an orderly development point of view, it appears to the Board that putting a second line parallel to the existing NOVA line would be preferable to routing it parallel to a line which is abandoned and where the right of way has been fully reclaimed. In reaching this conclusion, the Board acknowledges that the landowners along NOVA's existing right of way would be impacted again by the temporary disturbances associated with pipeline construction.

From the evidence put forward by Mr. Wilson, the Board accepts that there were reclamation problems on the 1981 construction which could perhaps be avoided or the impact mitigated by better co-operation between the Wilsons and NOVA, and by a more careful approach to pipeline construction across grassland. The Board notes NOVA's commitment to employ a full-time environmental co-ordinator and a full-time topsoil inspector. The Board appreciates that NOVA has improved its winter construction techniques since 1981 and that the topsoil-stripping machine has had success in other places in the province. The Board also notes that NOVA's experience with the Wilsons' land should give it useful prior knowledge for any further construction across the same land. The Board is therefore satisfied that the right of way across the Wilsons' land could be successfully reclaimed.

Having in mind the need for the pipeline, and also that the pipeline to the north is abandoned and thus the existing NOVA line is the only "corridor", the conclusion that the land can be successfully reclaimed if care is taken, and the modest cost advantage of the NOVA proposed route, the Board is prepared to approve the application.

The Board is concerned about the introduction of Mayweed onto the Wilsons' property and expects NOVA to exercise every precaution against this. It notes that both NOVA and Mr. Wilson agree that the weed on his property is at least under control although not yet eradicated.

As conditions of approval, the Board will require that the full-time environmental and topsoil experts be on hand while crossing the Wilson lands. It will also require NOVA to notify the Board's Edmonton office as to when work will take place on the Wilson lands, and plans to have its staff visit the site during construction. The Board will contact the local Land Reclamation Officer and seek his co-operation to ensure

that the maximum care is taken respecting the disruption and reclamation of the sensitive wet regions along the proposed route. The Board expects that NOVA will consult regularly and often with the officer during construction and reclamation operations.

The Board will also require NOVA to provide access across the topsoil bank and the depressed pipeline ditch for the Wilsons' farm equipment and cattle until the topsoil is replaced in the ditch.

9 DECISION

The Board approves the application of NOVA (No. 851082) subject to the conditions set out in this report. Upon receipt of the necessary approval of the Minister of the Environment, it will issue the required permit.

DATED at Calgary, Alberta, on 4 December 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

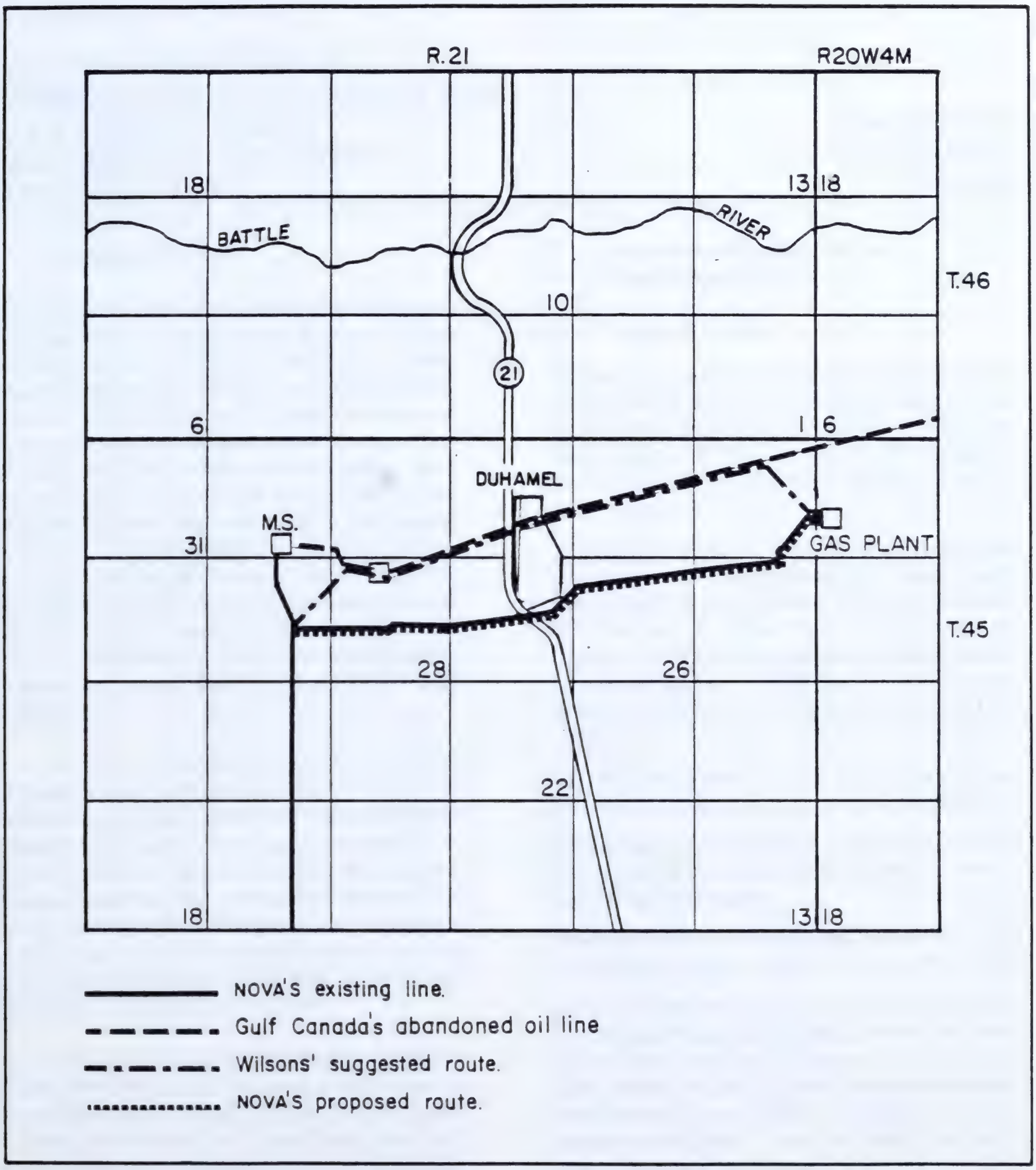
G. J. DeSorcy, P.Eng.
Vice Chairman

C. J. Goodman

C. J. Goodman, P.Eng.
Board Member

E. G. Fox

E. G. Fox, P.Eng.
Acting Board Member



NOVA'S PROPOSED PIPELINE AND A SUGGESTED ALTERNATIVE IN THE DUHAMEL AREA.

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

DOME PETROLEUM LIMITED COMMERCIAL OIL SANDS PROJECT AND WATER DISPOSAL SCHEME COLD LAKE OIL SANDS DEPOSIT PRIMROSE SECTOR

Decision D 85-44
Applications 850686 and 851114

1 INTRODUCTION

Dome Petroleum Limited (Dome), on behalf of itself and its partners, Canadian Hunter Exploration Ltd. (Canadian Hunter) and Pangaea Petroleum Limited (Pangaea), filed on 28 June 1985 Application 850686, pursuant to section 10 of the Oil Sands Conservation Act, for approval of a commercial oil sands project. The proposed project would recover crude bitumen from the Cold Lake Oil Sands Deposit via phased development of twenty sections of land in the Primrose Sector, as shown on the attached figure. In addition to this phased enhanced bitumen recovery (EBR) development, Dome proposes that its already existing EBR Moore Experimental Scheme in section 5-67-4 W4M (Approval No. 3489) be incorporated into the commercial project, and that its confidential status be maintained.

Dome also filed Application 851114 on 15 October 1985, in accordance with section 26 of the Oil and Gas Conservation Act, for approval to dispose of water produced in conjunction with Stage 1, sections 3, 4, 9, and 10-67-4 W4M of the aforementioned proposed five-stage, twenty-section commercial project. The proposed water disposal scheme would involve injection into the Granite Wash Formation through two wells located in legal subdivision 16 of section 4 and legal subdivision 10 of section 10-67-4 W4M.

Supportive material respecting environmental impacts and mitigative measures, including applications to Alberta Environment for permits and licences under the Clean Air Act and the Clean Water Act, land conservation and reclamation procedures, and socio-economic impacts associated with the project have also been filed by Dome.

2 THE APPLICATIONS

The details of the two applications are summarized below:

2.1 Commercial Oil Sands Project (Application 850686)

2.1.1 Technical Details

- The project would recover crude bitumen from the Clearwater "B" Formation of the Mannville Group. Recoverable reserves are estimated at 30.92 million cubic metres, or 18.6 per cent of the estimated project area original bitumen in place (165.8 million cubic metres).
- The project would be developed using a staged growth concept. Commencing in 1986 and in each year of the first 5-year period, a "stage" composed of a four-section square block of land would be started up. The total project crude bitumen production capacity of 4000 cubic metres per day would be achieved in 1991, when all five stages are on stream.
- 104 initial wells would be slant drilled in each stage on 2.4-hectare spacing in clusters of 24-28 wells.
- Production levels would be maintained over the project life by developing an additional 312 wells in each of the five stages.
- Water treatment and steam generation facilities would be centrally located within each of the five stages.
- Two central processing facilities would be constructed. The first central processing facility would be located in the Stage 1 area and is designed to handle 2400 cubic metres per day of crude bitumen production from Stages 1, 2, and 3. The second facility would be located in the Stage 4 area to handle 1600 cubic metres per day of production from Stages 4 and 5.
- During normal steady state operations, the project would require 14 250 cubic metres per day of water for steam generation (13 000 cubic metres per day) and water treatment system regeneration (1250 cubic metres per day). Approximately 8500 cubic metres per day, or 60 per cent, would be recycled produced water with the balance from local groundwater sources. The groundwater requirements would

increase gradually with the staged growth of the project, reaching the full steady state requirement of 5750 cubic metres per day in year six. However, the groundwater supply and treatment system would be designed to provide for start-ups, shut-downs, upsets, and other periods when produced water is temporarily unavailable and maximum steam generation is required.

- Fuel demand for the project is contingent on steam generation requirements. At full five-stage operation, the average fuel gas demand would be 1 240 000 cubic metres per day. At that time, approximately 125 000 cubic metres per day of produced gas is predicted to be available; the balance would be natural gas provided by Novacorp Pipelines Ltd.
- Condensate diluent requirements are expected to be 50 per cent of the bitumen production, peaking therefore at 2000 cubic metres per day. Dome is confident that its own condensate supply is adequate to satisfy all diluent requirements for all of its planned bitumen production through 1995.
- The expected commercial project life, without post-cyclic steam stimulation or recovery enhancement of some form, is 30 years. During this period, a total of 2080 wells would have been drilled from 80 pads serving the twenty sections of land in the project area. A constant bitumen production level of 4000 cubic metres per day would have been maintained for approximately 17 years when all five stages were operating. The proposed pad layout would then allow for infill drilling and/or the incorporation of other recovery methods in the future as they become technically and economically viable. These prospective techniques would be initially tested at the Moore pilot area before full-scale field implementation.

The Board has reviewed the technical details of the project and is satisfied with the drilling, completion, and production strategy as presented by Dome. Furthermore, the Board believes the phased approach, combined with the continued experimentation in the pilot area, will allow for incorporation of technological advances that may result in improved efficiency of the project as well as reducing environmental impacts.

The Board has some concern respecting the attainment of only an 18.6 percent recovery level based on the technology proposed by Dome; however, it accepts Dome's commitment to continue experimentation and would expect Dome to apply any improvements to the project when developed. Dome would also be expected to confirm the recovery level as the project proceeds. Furthermore, the Board expects Dome to continue experimentation with follow-up recovery methods. The Board will condition any approval issued to ensure that this is accomplished.

Dome requested that the existing pilot area be incorporated into the commercial scheme, but that the confidentiality of the information obtained continue to be maintained. The Board is satisfied that the request is reasonable but that this confidentiality should not be maintained for an indefinite period. Furthermore, the Board expects Dome to continue to confirm that the work being carried out is clearly directed towards the development of new technology. In this regard, the Board will condition any approval to limit the period of confidentiality to 3 years from the date of the approval and to require Dome to satisfy the Board as to the experimental nature of the work on an annual basis.

2.1.2 Socio-economic Impacts of the Commercial Oil Sands Scheme

Through a series of meetings and open-house programs, Dome presented details of the commercial development to business, public interest, and Native groups, and to municipal and provincial government representatives. A generally positive response to the proposed project was reported. In summary:

- Construction is to begin in early 1986 with plant start-up later that year.
- Capital expenditures during the initial 6-year period are estimated to be $575 million (1984 dollars); predicted on-going capital outlays averaging $58 million per year add approximately $925 million (1984 dollars) for a total project capital cost of $1.5 billion (1984 dollars).
- Project operating costs are predicted to average $140 million per year, resulting in an estimated total operating cost of $3.1 billion (1984 dollars) over the 30-year project life.
- 160 construction jobs would be created throughout the construction period 1986-1991, with 53 being filled by workers from the local area. Some 100 on-going construction, drilling, and servicing jobs would be created until approximately 2010, when on-going construction should terminate. In addition, about 190 permanent jobs would be created as part of on-going operations by Dome and its servicing contractors.
- The population increase associated with the project is predicted to be 1100 by 1991.

Dome intends to continue providing information programs and assistance to local communities with respect to employment opportunities and the project's construction and operation job requirements. As well, Dome plans to continue to assist local business by providing information and discussing opportunities for the supply of goods and services related to the project. Such policies will maximize the Canadian content of the project and provide industrial benefits to Alberta and Canada. Dome plans to open an office in Bonnyville to manage the project and to administer these policies and practices.

The Board is satisfied that Dome has adequately addressed the prospects for regional social and economic impact resulting from the project. The Board also considers that the project socio-economic impacts can be largely accommodated within the existing infrastructure and services of the region.

2.1.3 Environmental Impacts

Dome is confident that the proposed commercial project would develop the oil sands resources in a manner consistent with effective conservation practices and minimal environmental impact. All regulations governing the environment and resource use would be complied with. Co-operation with various government departments regarding regional plans and objectives would continue. All construction and operation activities would be undertaken so as to avoid or minimize undesirable biophysical environmental impacts. Furthermore, due to the staged growth, these disturbances would be spread over the project life. Specific environmental details are summarized below.

- Approximately 9 per cent of the total project area would be disturbed by construction activities during the project life. Land requirements would be minimized through the use of centralized, multi-well pads, and common access corridors for roads, pipelines, and powerlines.
- Only a small portion of wildlife habitat in the project area would be affected. Habitat alteration is expected to enhance the environment for moose and deer due to the increased open land space. Public access to the Air Weapons Range is prohibited; consequently, there are no hunting, trapping, or fishing activities to be affected by the project.
- Produced gases would be recovered for use as auxiliary fuel. Air quality effects would be low due to predicted low emissions that would be spread over a large area. An air quality monitoring program would be implemented.
- Dust control measures would be implemented. Maintenance of the project private road would be Dome's responsibility.
- All affected lands would be reclaimed to a state similar to that which existed before any disturbance took place.

The Board is satisfied that the environmental impacts of the project would be minor in nature. Furthermore, the phasing of the project provides an opportunity for adjustments and improvements in operating details and equipment design to minimize any impacts. In addition, monitoring requirements included in permits and licensing under the Clean Air Act and Clean Water Act would ensure that emissions are being kept to acceptable levels.

2.2 Water Disposal Scheme (Application 851114)

Waste water for disposal includes fresh water treatment wastes, produced water treatment wastes, and excess produced water. The maximum possible disposal rate for the project would occur during a produced water treatment plant shut-down or upset.

The anticipated normal and maximum disposal volumes per stage would be 250 cubic metres per day and 2400 cubic metres per day respectively.

Two disposal wells are planned for each stage. This would allow for unforeseen operational problems.

This specific application was for two disposal wells to handle up to 2400 cubic metres per day of water from Stage 1 of the project.

The Board is satisfied that the water disposal scheme as proposed by Dome is appropriate and that it will not result in any environmental problems. Furthermore, the well completion design, coupled with the monitoring conditions which will be included in any approval, will ensure that any problem is detected before it becomes serious in nature.

3 INTERVENTIONS

Applications 850686 and 851114 were advertised for a public hearing to be held in Bonnyville starting on 9 December 1985 with the proviso that the hearing would not be held if no interventions opposing the project were received. Canadian Hunter, Pangaea, Home Oil Company Limited, and BP Resources Canada Limited filed interventions for the purposes of cross-examination and argument only. The Town of Bonnyville filed a letter of support for the project. The Native Outreach Association of Alberta (Native Outreach), although not opposing the project, filed

an intervention respecting its concerns regarding the opportunities for Native employment and involvement in the project. This intervention was subsequently withdrawn on the basis of Dome's written commitment to meet with Native Outreach to discuss their concerns and to consider measures for addressing those concerns.

On the basis that there were no interventions opposing the applications and as the Board was satisfied with Dome's commitment to meet with Native Outreach, the hearing was cancelled.

4 THE DECISION

Having reviewed the details of the proposed commercial oil sands scheme and water disposal scheme, and having regard for the potential impacts and public benefits, the Board is prepared to grant Applications 850686 and 851114, with conditions. These conditions are shown in the draft form of the approval which is included as an appendix to this report.

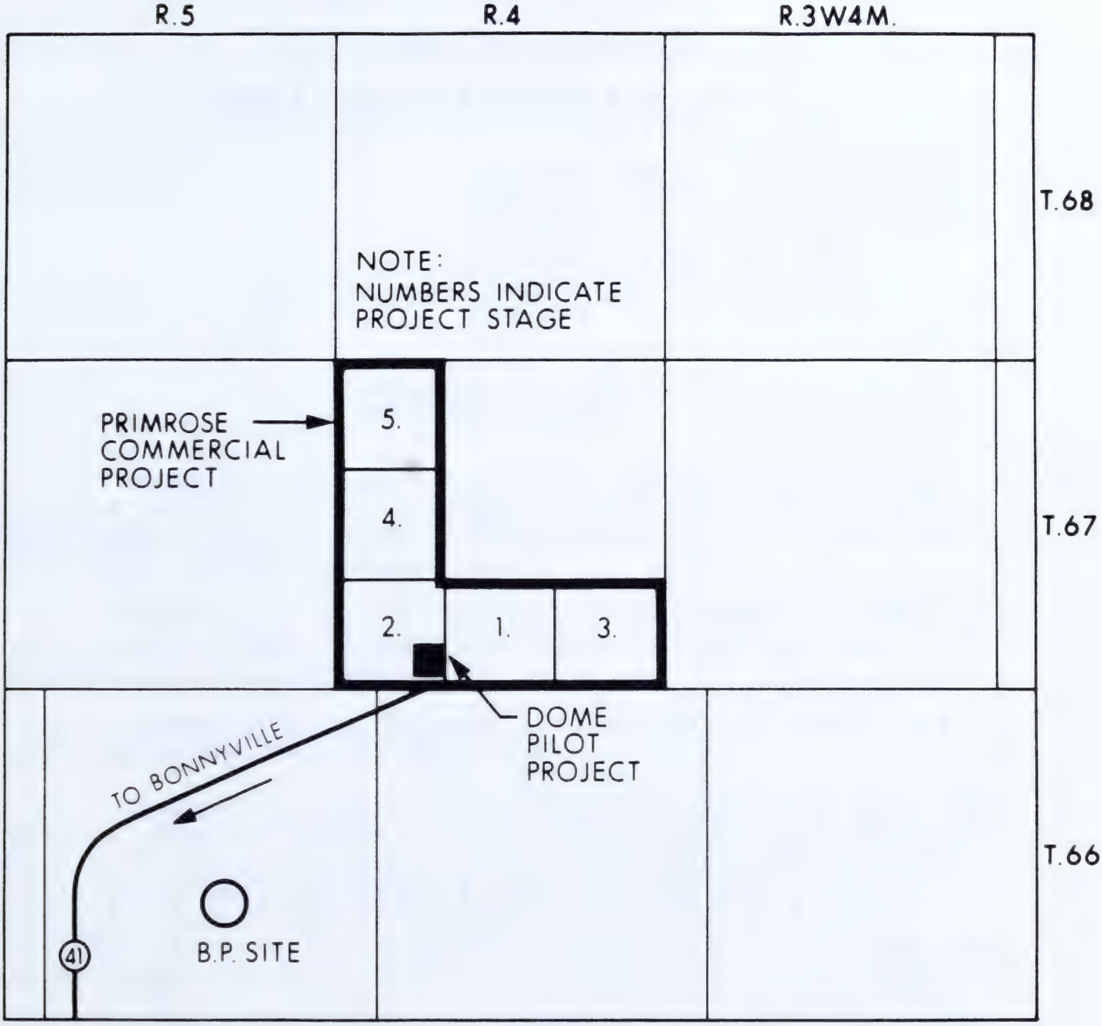
Subject to receipt of the necessary Order in Council and Ministerial Approvals, approvals for the project and the water disposal scheme will be issued.

DATED at Calgary, Alberta, on 18 December 1985.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman



DOME PETROLEUM LIMITED
APPLICATION NO. 850686
PRIMROSE COMMERCIAL OIL SANDS PROJECT

D 85-44

ERCB

DRAFT FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Dome Petroleum Limited for the recovery of crude bitumen from the Cold Lake Oil Sands Deposit in the Primrose Sector

APPROVAL NO. 4775

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Dome Petroleum Limited for a commercial oil sands scheme subject to the terms and conditions herein contained; and

WHEREAS the Board, by Approval No. 3489, approved an experimental scheme of Dome Petroleum Limited for the recovery of crude bitumen; and

WHEREAS the Board deems it desirable to revise and consolidate Approval No. 3489; and

WHEREAS the Minister of the Environment has given his approval, hereto attached, insofar as the application affects matters of the environment, and the Associate Minister of Public Lands and Wildlife has given his approval, hereto attached, insofar as the application affects land and resources that are the property of the Crown in the right of Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council number O.C. and dated , has authorized the granting of the approval subject to certain conditions set out in the Order in Council.

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* This is only a form of approval. The approval, when issued, may have minor variations from that set out here.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil Sands Conservation Act, being chapter O-5.5 of the Statutes of Alberta, 1983, hereby orders as follows:

1. (1) The scheme of Dome Petroleum Limited (hereinafter called "the Operator") for the recovery of crude bitumen from the Cold Lake Oil Sands Deposit in the area outlined on the attachment to this approval, marked Appendix A, as such scheme is described in Application No. 850686 dated 26 June 1985 and addenda thereto dated 9 October, 1, 12, 19 and 25 November 1985, is approved, subject to the terms and conditions herein contained.

(2) The Operator shall notify the Board of any proposed alteration or modification to the scheme or to any equipment proposed for use therein, prior to effecting the alteration or modification.

(3) Where, in the opinion of the Board, any alteration or modification of the scheme or to any equipment proposed for use therein

(a) is not of a minor nature,

(b) is not compatible with the scheme approved herein, or

(c) may not result in an improved or more efficient scheme or operation,

the alteration or modification shall not be proceeded with or effected without the further authorization of the Board.

2. This approval is for a project which will include the provision of confidential status until 31 January 1989 for information obtained from wells and operations located in Legal Subdivisions 9, 10, 15 and 16 of Section 5, Township 67, Range 4, West of the 4th Meridian, with the exception of total monthly production data from the wells in that area, and the Operator shall provide the Board with information annually which will allow the Board to verify the experimental nature of the area operations.

3. Notwithstanding clause 2,

(1) The Operator shall file with the Board the details of any special well completions, studies, cost data, laboratory data and core or log evaluations completed for any

portion of the commercial scheme or for the development or application of new technology or improved operations.

(2) The Board may accept the information referred to in subclause (1) as confidential in cases where the Operator satisfies the Board that the release of the data would result in a serious loss of significant proprietary value.

(3) The information accepted as confidential by subclause (2) will be released to the public after 5 years from the submission date unless, upon application by the Operator or if other circumstances so warrant, a further period of confidentiality is approved by the Board.

4. (1) This approval is for the production of crude bitumen of a maximum of 4000 cubic metres per day on an annual average basis.

(2) The Operator shall make application to the Board for any changes to the scheme that would cause crude bitumen production to exceed that specified in subclause (1).

5. The Operator shall conduct all operations to the satisfaction of the Board and in a manner that, under normal operating conditions, will ensure

(a) the recovery from the oil sands deposit of the practical maximum of crude bitumen,

(b) the gathering and utilization of the practical maximum amount of gas produced, including casing vent gases,

(c) the avoidance of waste of liquid or gaseous hydrocarbons, and

(d) the efficient transportation of crude bitumen to market.

6. (1) The Operator shall measure and record, to the satisfaction of the Board, the volumes and other pertinent characteristics of all fluids injected and produced and other streams as may be required by the Board.

(2) The measurements referred to in subclause (1) shall be made with sufficient frequency and accuracy as to allow a calculation, to the satisfaction of the Board, of mass balances, energy balances and recovery efficiencies of the production processes.

7. The Operator shall, prior to 30 June 1989, submit to the Board updated projections of cyclic steam well performance based on a minimum of two complete cycles of steam injection and crude bitumen production from all eligible wells within the project to verify or change rate-time performance predictions filed in Application No. 850686.

8. (1) The Operator shall, commencing 30 September 1986, submit a report to the Board by 30 September of each year showing the proposed development plan for the next calendar year.

(2) The report required by subclause (1) shall include maps and related schedules showing

(a) the location and year of development of all existing well pads and well pads proposed to be developed during the next calendar year,

(b) the location and year of suspension or abandonment of existing well pads and well pads proposed to be suspended or abandoned during the next calendar year,

(c) satellites proposed to be relocated during the next calendar year, and

(d) such other information as the Board may require.

9. During construction of the project facilities and drilling of the project wells, the Operator shall semi-annually report the progress of construction and site development to the Board.

10. (1) The Operator shall drill not less than four evenly spaced wells per section to the base of the Mannville Group; for three of the four wells, core shall be taken from the Clearwater Formation reservoir section; from the fourth well, core shall be taken of the bitumen-bearing sections of the Mannville Group; the core shall be analysed and the clean-cut surface of the slabbed core shall be photographed.

(2) A full logging suite is defined to be a compensated neutron log, a formation density compensated log, a gamma ray log, a dual induction lateral log and a spontaneous potential log.

(a) Each of the wells referred to in subclause (1) shall be logged over the entire Mannville Group by means of a full suite.

(b) Twelve additional evenly spaced wells per section shall be logged by means of a full suite from total depth to the top of the Mannville Group.

(3) All remaining wells shall be logged from total depth to the top of the Mannville Group by means of a gamma ray-dual induction lateral log type device.

(4) The Operator shall provide directional surveys, top and bottom hole co-ordinates and true vertical depth corrected logs for all deviated wells.

(5) The Operator shall notify the Board's Geology Department of any proposed changes to the minimum coring and logging requirements specified in subclauses (1), (2), (3) and (4) prior to their implementation.

11. The Operator shall, not later than 1 April of each year, submit to the Board current estimates and appropriate supporting maps showing the volume of crude bitumen and gas in place in the sands of each formation of the Mannville Group within the project development area, based on drilling completed by 31 December of the previous year.

12. Prior to the commencement of steam injection operations at any well pad, the Operator shall submit to the Board its evaluation of the volume of crude bitumen and gas in place in the Clearwater Formation within that part of the reservoir associated with that well pad.

13. (1) Following the commencement of steam injection or crude bitumen production operations, the Operator shall file with the Board, on forms provided by or satisfactory to the Board,

(a) monthly hydrocarbon and water balance reports for

(i) the production and injection facilities,

(ii) any water treatment facilities, and

(iii) the overall project;

(b) a performance evaluation report summarizing all activities and operations carried out, including

(i) hydrocarbon and water balances over the report period, in a format similar to that required monthly by subclause (1), paragraph (a),

(ii) energy balances over the report period of the overall project,

(iii) a discussion of any unusual drilling, completion, production or injection problems encountered at specific wells,

(iv) details of any major operating incidents,

(v) a review of any operations conducted to reclaim or dispose of sand and oily waste generated by the project,

(vi) an assessment of the efficiency of injection and production operations,

(vii) a review of operations conducted to minimize the make-up water requirements, and

(viii) such other information as the Board from time to time may require.

(2) The reports required by subclause (1), paragraph (a) shall be filed by the 15th day of the month following that month for which the balances are being reported.

(3) Four copies of the reports required by subclause (1), paragraph (b) shall be submitted semi-annually for the first 5 years for operating periods ending 30 June and 31 December, and annually thereafter, and shall be filed within 60 days of the expiration of the report period.

14. The Operator shall apply to the Board's Pipeline Department for all pipeline permits, prior to commencing implementation.

15. (1) The Operator shall take such steps and effect such measures as may be necessary in the completing and operation of wells to prevent production casing failures.

(2) The Operator shall, prior to commencing steaming operations, submit to the Board for its approval a monitoring program designed to ensure early detection of any production casing failures.

16. The Operator shall, prior to start-up, submit to the Board and the Department of the Environment a monitoring program satisfactory to the Board and the Department of the Environment to ensure early detection of any contamination of fresh water aquifers or surficial ground water that may be caused by scheme operations.

17. The Operator, subject to such terms and conditions as may be prescribed by the Board upon considering an application therefor, shall undertake extensive field investigations of in situ combustion, steam flooding and any other alternative or follow-up recovery method that the Operator believes may have potential application in the Clearwater Formation.

18. The Operator shall conduct recovery tests satisfactory to the Board in the McMurray and Grand Rapids Formations in the project development area to determine the practicality of recovering bitumen from these formations and provide the results of such tests to the Board.

19. (1) Unless otherwise permitted by the Board, cyclic steam stimulation operations, having commenced at a well pad, shall continue until the well pad has produced a minimum of 18.6 per cent of the in-place volume of crude bitumen assigned to that well pad by the Board.

(2) Where the Operator proposes to cease cyclic steam stimulation operations at a well pad that has produced less than 18.6 per cent of the in-place volume of crude bitumen, the Board's consent therefore must be sought, and the Operator shall advise the Board as to the following:

(a) the reason for proposing to cease cyclic steam stimulation operations,

(b) details of individual well workovers and recompletions attempted,

(c) details of any infill drilling attempted,

(d) detailed economics of continuing operations, and

(e) future plans for the well pad with reference to possible follow-up recovery techniques that could be applied and other zones that could be exploited.

20. The Operator shall dispose of produced sand in an environmentally safe manner satisfactory to the Board.

21. The Operator shall, not later than 1 January 1987, submit to the Board spill contingency plans for the scheme in the detail specified in the Board's Interim Directive No. ID-OG-PL 75-1.

22. (1) If crude bitumen, salt water or other substance other than fresh water is spilled from any equipment or facility associated with the scheme, the Operator shall take immediate steps to contain and clean up the spill.

(2) Where a spill occurs from a facility described in subclause (1), and

(a) the substance is not confined to the site of the facility from which the spill occurred, or

(b) the volume of substance spilled is in excess of 2 cubic metres,

the Operator shall immediately report the size and location of the spill to the Board.

(3) When so directed by the Board, a report made pursuant to subclause (2) shall, within 2 weeks of the date of the spill, be confirmed in a written report to the Board and be supplemented with at least the following additional information:

(a) the time the spill occurred,

(b) a description of the circumstances leading to the spill,

(c) a discussion of actions taken in response to the spill,

(d) a discussion of steps to be taken to prevent similar future spills, and

(e) an outline and schedule for the spill site rehabilitation program.

23. (1) Attached hereto as Appendix B to this approval is the order of the Lieutenant Governor in Council authorizing the granting of the approval.

(2) This approval is subject to the terms and conditions prescribed by the order of the Lieutenant Governor in Council set out in Appendix B.

24. This approval, insofar as it pertains to matters of the environment, is subject to the approval of the Minister of the Environment, hereto attached as Appendix C to this approval, and insofar as it pertains to matters that affect land and resources that are the property of the Crown in the right of Alberta, is subject to the approval of the Associate Minister of Public Lands and Wildlife, hereto attached as Appendix D to this approval, and to the terms and conditions therein contained.

25. (1) The Board may,

(a) upon its own motion, or

(b) upon the application of an interested person,

rescind or amend this approval at any time if, in the opinion of the Board, circumstances so warrant.

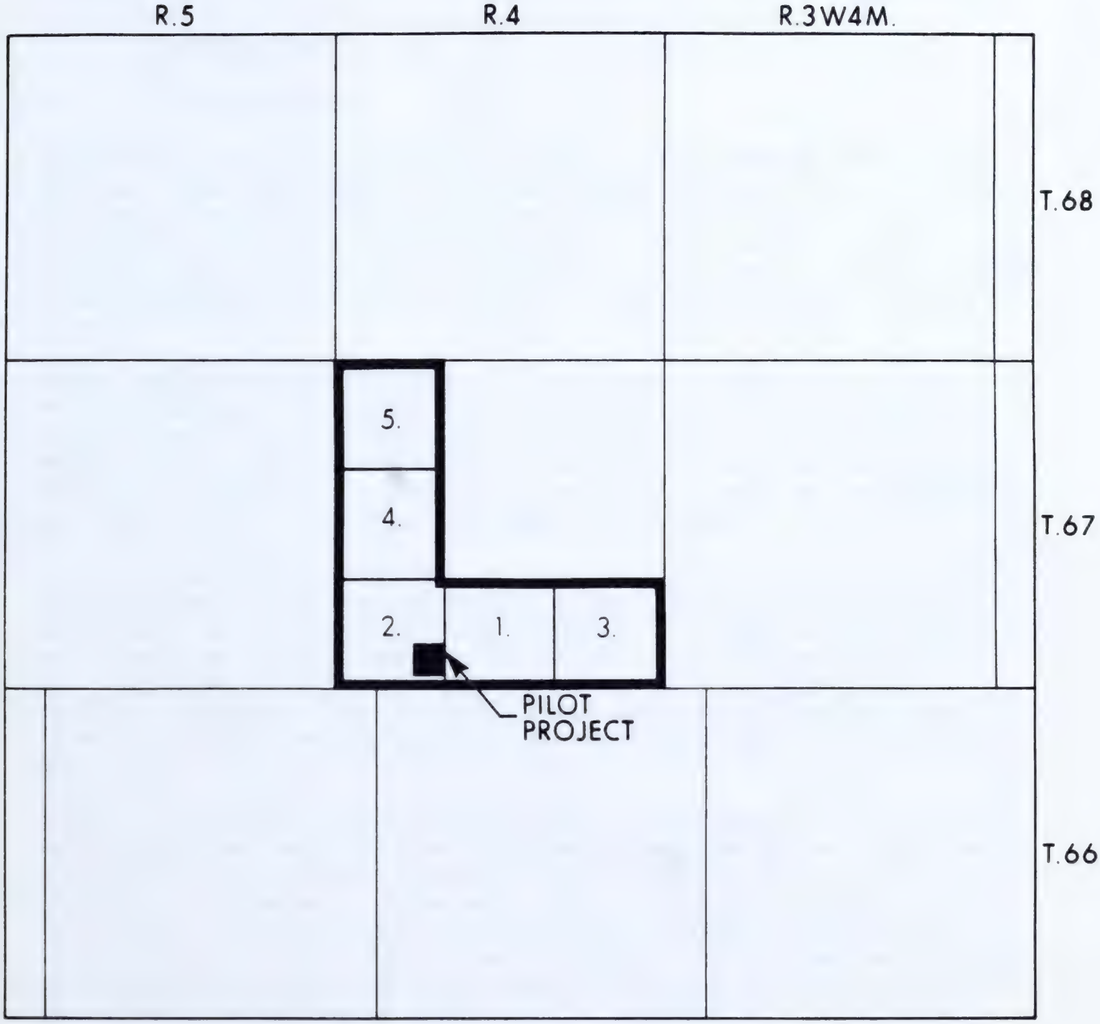
(2) This approval, unless rescinded before that date, expires on 31 January 2016 unless upon application by the Operator a later date is approved by the Board.

26. Board Approval No. 3489 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman



COLD LAKE OIL SANDS DEPOSIT
APPENDIX A TO APPROVAL NO. 4775

NOTE:
1. PRIMROSE COMMERCIAL PROJECT DEVELOPMENT AREA
2. NUMBERS INDICATE PROJECT STAGE.

D85-44
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SUNCOR INC.
COMMERCIAL OIL SANDS PROJECT
PRIMROSE SECTOR

Decision D 85-45
Application 850952

1 INTRODUCTION

1.1 The Application

Suncor Inc. (Suncor), on behalf of itself, Alberta Energy Company Ltd., Canadian Hunter Exploration Ltd., and Pangaea Petroleum Limited, applied pursuant to section 10 of the Oil Sands Conservation Act for approval of a commercial oil sands project. The project would recover crude bitumen resources from the Cold Lake Clearwater Oil Sands Deposit using a cyclic steam stimulation recovery technique. The project location is shown in Figure 1.

Suncor would develop the project in four stages (Figure 2), each of which is designed to recover up to 1000 cubic metres per day (m^3/d) of crude bitumen over a 25-year life. Suncor requested approval of the entire 4-stage project with specific approval to construct and operate Stage 1. Approval of the remaining three stages would be conditional upon the filing of additional detailed information.

Stage 1 would initially require the drilling of 110 wells. Up to 360 additional wells would be required over the life of the stage in order to maintain the 1000 m^3/d level of productivity. Approximately 2000 wells would be drilled over the life of the entire 4-stage project. Wells would be drilled from pads using both slant and directional drilling techniques. The first 110 wells would be drilled from two 25-well pads (2.6-hectare spacing) and two 30-well pads (2.2-hectare spacing).

Central processing facilities would also be constructed in association with Stage 1 and would include the necessary equipment for production treatment, produced water treatment, fresh water treatment, and steam generation. Subsequent stages would require expansion of these facilities. The facilities for Stages 2 and 3 would be constructed adjacent to the Stage 1 facilities. The Stage 4 facilities would either be constructed adjacent to the previous facilities or at a location approximately 4 kilometres north.

1.2 Interventions

An intervention expressing opposition to Suncor's application was filed by the Town of Cold Lake (the Town). The Town was in support of the project in general but opposed to the proposed water source.

Interventions in the form of notices of intent to appear were filed by Canadian Hunter Exploration Ltd., Home Oil Company Limited, and Pangaea Petroleum Limited.

Mr. A. D. Jacob appeared at the hearing representing the Cold Lake First Nations. He did not register as an intervener; however, he did present a number of general concerns during a closing statement.

Interventions opposing the proposed project were filed by Mr. Tim Kalinski and Ms. Betty Duckett, both owners of registered traplines. Their interventions were primarily compensation related and were withdrawn prior to the hearing.

1.3 The Hearing

The application was heard at a public hearing in Grand Centre, Alberta, on 17 December 1985, before Board members G. J. DeSorcy, P.Eng., L. A. Bellows, P.Eng., and acting Board member E. G. Fox., P.Eng. Those who appeared at the hearing are shown in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Suncor Inc. (Suncor) K. S. MacFarlane	E. J. Paholko, P.Eng. B. R. Wilson, P.Eng. J. F. Doyle, P.Eng. K. C. Yeung, P.Eng. F. J. Lobkowicz, P.Geol. C. W. Fulton, P.Eng.
The Town of Cold Lake (the Town) Mayor W. Johnston	Mayor W. Johnston
Canadian Hunter Exploration Ltd. (Canadian Hunter) K. F. Miller	
Cold Lake First Nations A. D. Jacob	
Energy Resources Conservation Board staff M. J. Bruni R. G. Evans, P.Eng. T. G. Abel, E.I.T. M. MacRae	

2 ISSUES

The Board considers the following to be the issues of primary concern respecting Suncor's proposed project:

- fresh water source
- staged concept of development
- recovery estimate.

3 FRESH WATER SOURCE

Suncor stated that it was issued Interim Licence No. 14055 by the Water Resources Administration Division of Alberta Environment for the withdrawal of the effluent water from the Cold Lake Fish Hatchery (the Fish Hatchery). The licence gives Suncor approval to divert up to 2629 dam^3 annually (7200 m^3/d). Suncor believes that the use of water from the Fish Hatchery is consistent with the Long Term Water Management Plan for the area and will not adversely impact the area and its residents. Fresh water withdrawals have been minimized through Suncor's commitment to recycle all of its produced water which will provide approximately 70 per cent of the total water requirement for the project.

The Town did not oppose the use of the effluent in the short term, but believed that Suncor should be required to tie into the North Saskatchewan water pipeline when it is completed. It did not agree that the use of the Fish Hatchery effluent should be included as a legitimate use of lake water in the Long Term Water Management Plan. This is in part because it did not believe that the return of the effluent to the lake would have any detrimental effects, but rather that it may have some positive impacts. The Town stated that approving the long-term use of the Fish Hatchery effluent could seriously jeopardize the economics of the pipeline and could set a precedent for other companies to avoid using the pipeline.

Canadian Hunter stated that it believed that compliance with any policy respecting the water resources of the province is the responsibility of the Minister of the Environment. It further believed that those issues raised by the Town respecting the withdrawal of water were considered and addressed in the interim licence issued by Alberta Environment.

The Cold Lake First Nations welcomed the use of the Fish Hatchery effluent by Suncor. It stated that in the future it hoped the Fish Hatchery would not circulate an unwarranted amount of fresh water from Cold Lake to meet the increasing needs of the Suncor project and also asked that the ERCB strictly monitor lake levels.

The Board recognizes the fact that Alberta Environment has issued an interim approval to Suncor for the use of the Cold Lake Fish Hatchery effluent. The Board believes that Alberta Environment has carefully considered all the potential environmental impacts associated with the use of this effluent. The Board recognizes the concerns regarding the water source expressed by the interveners and will undertake to ensure that the Minister of the Environment is made aware of those concerns.

With regard to the request by the Cold Lake First Nations that the ERCB monitor lake levels, the Board believes that such would be redundant and therefore unnecessary. The Board has approached Alberta Environment in this regard and is satisfied that it currently addresses and deals with the monitoring of lake levels in an acceptable manner.

4 STAGED CONCEPT OF DEVELOPMENT

Suncor applied for approval of a 4-stage commercial oil sands project. The specific details of the project were only provided for the first stage of the project and Suncor requested that the approval of the remaining three stages be conditional on the filing of additional detailed technical information. Suncor stated that it was also willing to submit additional applications for Stages 2, 3, and 4 if the Board so required.

The Board commends Suncor for presenting to the public and the Board a complete overview of the project as it is currently envisioned. The Board notes that this is consistent with the requests of many concerned groups in the area. However, while the Board is prepared to issue an approval relating to the total project area, it believes that additional applications must be made to the Board for its approval regarding the specific details of the remaining stages.

5 RECOVERY ESTIMATE

Suncor has stated that it believes it can attain a recovery of 20 per cent of the crude bitumen in place. This recovery estimate was established using data from Suncor's experimental project at Fort Kent and the experience of other operators in the area.

While the Board is prepared at this time to accept a recovery of 20 per cent, it does have one concern that this estimate may be too low. In this regard, the Board would expect Suncor to continue experimentation with cyclic steam recovery and apply any improvements to the project if and when they are developed. The Board further expects Suncor to experiment with other recovery methods for the purpose of improving the ultimate recovery of bitumen from the project. The Board also believes that Suncor should study the occurrence and development of other oil sands reserves within the proposed project area. To ensure that these expectations are met by Suncor, the Board will condition any approval issued by it accordingly.

6 DECISION

The Board, having reviewed the evidence provided by the applicant and the interveners, is satisfied that the project is technically and environmentally sound and would result in substantial economic benefits to both the region and the province. The Board is therefore prepared to approve Application 850952 with conditions. These conditions are shown in the draft form of approval which is included as an appendix to this report.

Subject to the receipt of an Order in Council authorizing the granting of the approval and ministerial approvals from the Minister of the Environment and the Associate Minister of Public Lands and Wildlife, the Board will issue its approval for the project.

DATED at Calgary, Alberta, on 15 January 1986.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Vice Chairman

L A Bellows

L. A. Bellows, P.Eng.
Board Member

E G Fox

E. G. Fox, P.Eng.
Acting Board Member

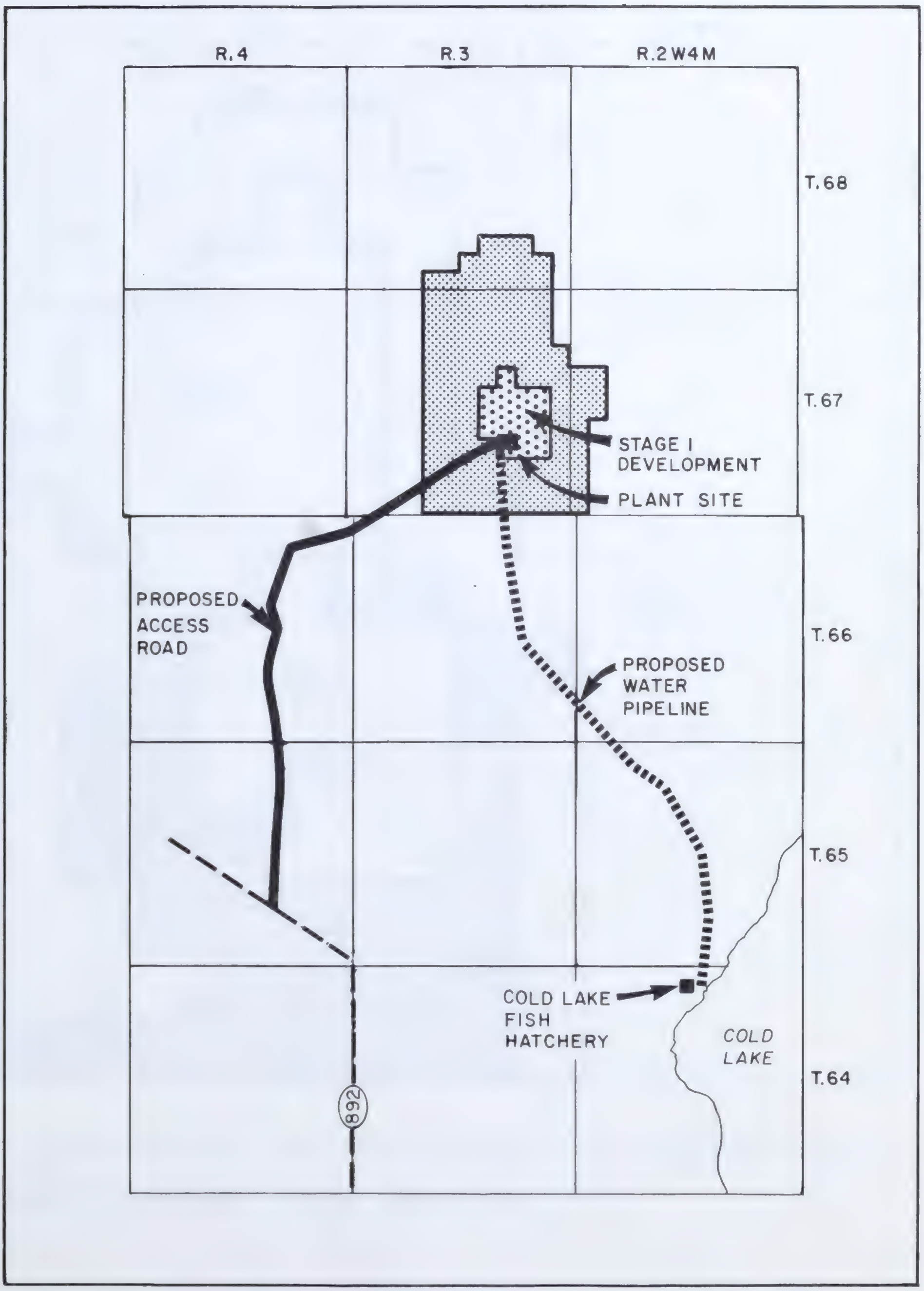


FIGURE I PROJECT LOCATION

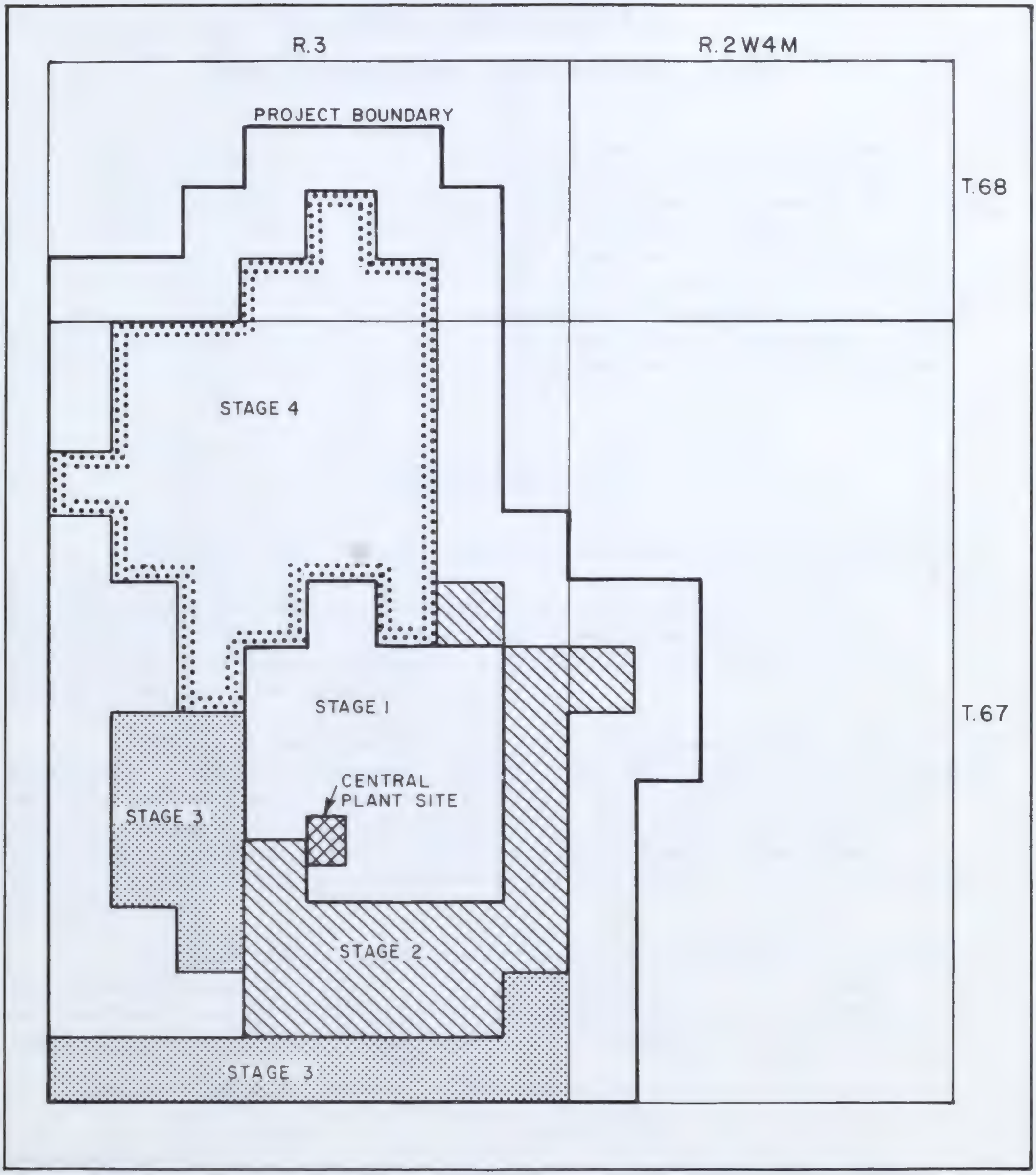


FIGURE 2 PROPOSED STAGE LOCATIONS

DRAFT FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Suncor Inc., on behalf of itself, Alberta Energy Company Ltd., Canadian Hunter Exploration Ltd. and Pangaea Petroleum Limited, for the recovery of crude bitumen from the Cold Lake Clearwater Oil Sands Deposit in the Primrose Sector

APPROVAL NO. 4785

WHEREAS the Energy Resources Conservation Board is prepared to grant an application by Suncor Inc., on behalf of itself, Alberta Energy Company Ltd., Canadian Hunter Exploration Ltd. and Pangaea Petroleum Limited, for a commercial oil sands scheme, subject to the terms and conditions herein contained; and

WHEREAS the Minister of the Environment has given his approval, hereto attached, insofar as the application affects matters of the environment, and the Associate Minister of Public Lands and Wildlife has given his approval, hereto attached, insofar as the application affects land and resources that are the property of the Crown in the right of Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council number O.C.   and dated   , has authorized the granting of the approval subject to certain conditions set out in the Order in Council.

---

* This is only a form of approval. The approval, when issued, may have minor variations from that set out here.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Oil Sands Conservation Act, being chapter 0-5.5 of the Statutes of Alberta, 1983, hereby orders as follows:

1. (1) The scheme of Suncor Inc. (hereinafter called "the Operator") on behalf of itself, Alberta Energy Company Ltd., Canadian Hunter Exploration Ltd. and Pangaea Petroleum Limited, for the recovery of crude bitumen from the Cold Lake Clearwater Oil Sands Deposit in the area outlined on the attachment to this approval, marked Appendix A, as such scheme is described in Application No. 850952 dated 11 September 1985 and addenda thereto dated 16 September 1985, 4, 9 and 22 October 1985, 12 and 13 November 1985, is approved, subject to the terms and conditions herein contained.

(2) The Operator shall notify the Board of any proposed alteration to the scheme or to any equipment proposed for use therein, prior to effecting the alteration or modification.

(3) Where, in the opinion of the Board, any alteration or modification of the scheme or to any equipment proposed for use therein

(a) is not of a minor nature,

(b) is not compatible with the scheme approved herein, or

(c) may not result in an improved or more efficient scheme or operation,

the alteration or modification shall not be proceeded with or effected without the further authorization of the Board.

2. (1) The Operator shall file with the Board the details of any special well completions, studies, cost data, laboratory data and core or log evaluations completed for any portion of the commercial scheme or for the development or application of new technology or improved operations.

(2) The Board may accept the information referred to in subclause (1) as confidential in cases where the Operator satisfies the Board that the release of the data would result in a serious loss of significant proprietary value.

(3) The information accepted as confidential by subclause (2) will be released to the public after 5 years

from the submission date unless, upon application by the Operator or if other circumstances so warrant, a further period of confidentiality is approved by the Board.

3. (1) This approval is for the production of crude bitumen from the Stage 1 development area to a maximum of 1000 cubic metres per day on an annual average basis.

(2) The Operator shall make application to the Board for any changes to the scheme that would cause crude bitumen production to exceed that specified in subclause (1).

4. The Operator shall conduct all operations to the satisfaction of the Board and in a manner that, under normal operating conditions, will ensure

(a) the recovery from the oil sands deposit of the practical maximum of crude bitumen,

(b) the gathering and utilization of the practical maximum amount of gas produced, including casing vent gases,

(c) the avoidance of waste of liquid or gaseous hydrocarbons, and

(d) the efficient transportation of crude bitumen to market.

5. (1) The Operator shall measure and record, to the satisfaction of the Board, the volumes and other pertinent characteristics of all fluids injected and produced and other streams as may be required by the Board.

(2) The measurements referred to in subclause (1) shall be made with sufficient frequency and accuracy as to allow a calculation, to the satisfaction of the Board, of mass balances, energy balances and recovery efficiencies of the production processes.

6. The Operator shall, prior to 30 June 1989, submit to the Board updated projections of cyclic steam well performance based on a minimum of two complete cycles of steam injection and crude bitumen production from all eligible wells within the project to verify or change rate-time performance predictions filed in Application No. 850952.

7. (1) The Operator shall, commencing 30 September 1986, submit a report to the Board by 30 September of each

year showing the proposed development plan for the next calendar year.

(2) The report required by subclause (1) shall include maps and related schedules showing

(a) the location and year of development of all existing well pads and well pads proposed to be developed during the next calendar year,

(b) the location and year of suspension or abandonment of existing well pads and well pads proposed to be suspended or abandoned during the next calendar year,

(c) satellites proposed to be relocated during the next calendar year, and

(d) such other information as the Board may require.

8. During construction of the project facilities and drilling of the project wells, the Operator shall semi-annually report the progress of construction and site development to the Board.

9. (1) The Operator shall drill not less than four evenly spaced wells per section to the base of the Mannville Group; for three of the four wells, core shall be taken from the Clearwater Formation reservoir section; from the fourth well, core shall be taken of the bitumen-bearing sections of the Mannville Group; the core shall be analysed and the clean-cut surface of the slabbed core shall be photographed.

(2) A full logging suite is defined to be a compensated neutron log, a formation density compensated log, a gamma ray log, a dual induction lateral log and a spontaneous potential log.

(a) Each of the wells referred to in subclause (1) shall be logged over the entire Mannville Group by means of a full suite.

(b) Twelve additional evenly spaced wells per section shall be logged by means of a full suite from total depth to the top of the Mannville Group.

(3) All remaining wells shall be logged from total depth to the top of the Mannville Group by means of a gamma ray-dual induction lateral log type device.

(4) The Operator shall provide directional surveys, top and bottom hole co-ordinates and true vertical depth corrected logs for all deviated wells.

(5) The Operator shall notify the Board's Geology Department of any proposed changes to the minimum coring and logging requirements specified in subclauses (1), (2), (3) and (4) prior to their implementation.

10. The Operator shall, not later than 1 April of each year, submit to the Board current estimates and appropriate supporting maps showing the volume of crude bitumen and gas in place in the sands of each formation of the Mannville Group within the project development area, based on drilling completed by 31 December of the previous year.

11. Prior to the commencement of steam injection operations at any well pad, the Operator shall submit to the Board its evaluation of the volume of crude bitumen and gas in place in the Clearwater Formation within that part of the reservoir associated with that well pad.

12. (1) Following the commencement of steam injection or crude bitumen production operations, the Operator shall file with the Board, on forms provided by or satisfactory to the Board,

(a) monthly hydrocarbon and water balance reports for

(i) the production and injection facilities,

(ii) any water treatment facilities, and

(iii) the overall project;

(b) a performance evaluation report summarizing all activities and operations carried out, including

(i) hydrocarbon and water balances over the report period, in a format similar to that required monthly by subclause (1), paragraph (a),

(ii) energy balances over the report period of the overall project,

(iii) a discussion of any unusual drilling, completion, production or injection problems encountered at specific wells,

(iv) details of any major operating incidents,

(v) a review of any operations conducted to reclaim or dispose of sand and oily waste generated by the project,

(vi) an assessment of the efficiency of injection and production operations,

(vii) a review of operations conducted to minimize the make-up water requirements, and

(viii) such other information as the Board from time to time may require.

(2) The reports required by subclause (1), paragraph (a) shall be filed by the 15th day of the month following that month for which the balances are being reported.

(3) Four copies of the reports required by subclause (1), paragraph (b) shall be submitted semi-annually for the first 5 years for operating periods ending 30 June and 31 December, and annually thereafter, and shall be filed within 60 days of the expiration of the report period.

13. The Operator shall apply to the Board's Pipeline Department for all pipeline permits, prior to commencing implementation.

14. (1) The Operator shall take such steps and effect such measures as may be necessary in the completing and operation of wells to prevent production casing failures.

(2) The Operator shall, prior to commencing steaming operations, submit to the Board for its approval a monitoring program designed to ensure early detection of any production casing failures.

15. The Operator shall, prior to start-up, submit to the Board and the Department of the Environment a monitoring program satisfactory to the Board and the Department of the Environment to ensure early detection of any contamination of fresh water aquifers or surficial ground water that may be caused by scheme operations.

16. The Operator, subject to such terms and conditions as may be prescribed by the Board upon considering an application therefor, shall undertake extensive field investigations of in situ combustion, steam flooding and any other alternative or follow-up recovery method that the Operator believes may have potential application in the Clearwater Formation.

17. The Operator shall conduct recovery tests satisfactory to the Board in the McMurray and Grand Rapids Formations in the project development area to determine the practicality of recovering bitumen from these formations and provide the results of such tests to the Board.

18. (1) Unless otherwise permitted by the Board, cyclic steam stimulation operations, having commenced at a well pad, shall continue until the well pad has produced a minimum of 20 per cent of the in-place volume of crude bitumen assigned to that well pad by the Board.

(2) Where the Operator proposes to cease cyclic steam stimulation operations at a well pad that has produced less than 20 per cent of the in-place volume of crude bitumen, the Board's consent therefor must be sought, and the Operator shall advise the Board as to the following:

(a) the reason for proposing to cease cyclic steam stimulation operations,

(b) details of individual well workovers and recompletions attempted,

(c) details of any infill drilling attempted,

(d) detailed economics of continuing operations, and

(e) future plans for the well pad with reference to possible follow-up recovery techniques that could be applied and other zones that could be exploited.

19. The Operator shall dispose of produced sand in an environmentally safe manner satisfactory to the Board.

20. The Operator shall, not later than 1 January 1987, submit to the Board spill contingency plans for the scheme in the detail specified in the Board's Interim Directive No. ID-OG-PL 75-1.

21. (1) If crude bitumen, salt water or other substance other than fresh water is spilled from any equipment or facility associated with the scheme, the Operator shall take immediate steps to contain and clean up the spill.

(2) Where a spill occurs from a facility described in subclause (1), and

(a) the substance is not confined to the site of the facility from which the spill occurred, or

(b) the volume of substance spilled is in excess of 2 cubic metres,

the Operator shall immediately report the size and location of the spill to the Board.

(3) When so directed by the Board, a report made pursuant to subclause (2) shall, within 2 weeks of the date of the spill, be confirmed in a written report to the Board and be supplemented with at least the following additional information:

(a) the time the spill occurred,

(b) a description of the circumstances leading to the spill,

(c) a discussion of actions taken in response to the spill,

(d) a discussion of steps to be taken to prevent similar future spills, and

(e) an outline and schedule for the spill site rehabilitation program.

22. (1) Attached hereto as Appendix B to this approval is the order of the Lieutenant Governor in Council authorizing the granting of the approval.

(2) This approval is subject to the terms and conditions prescribed by the Order of the Lieutenant Governor in Council set out in Appendix B.

23. This approval, insofar as it pertains to matters of the environment, is subject to the approval of the Minister of the Environment, hereto attached as Appendix C to this approval, and insofar as it pertains to matters that affect land and resources that are the property of the Crown in the right of Alberta, is subject to the approval of the Associate Minister of Public Lands and Wildlife, hereto attached as Appendix D to this approval, and to the terms and conditions therein contained.

24. (1) The Board may,

(a) upon its own motion, or

(b) upon the application of an interested person,

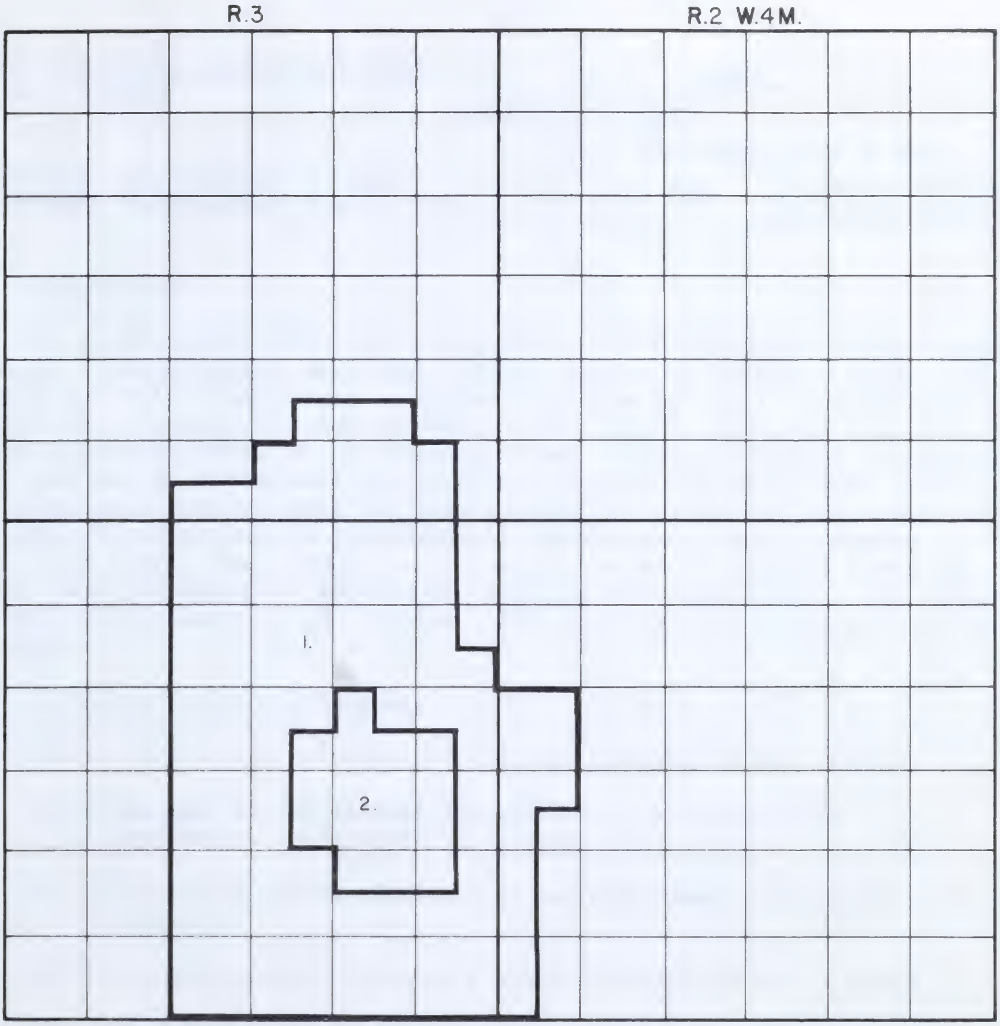
rescind or amend this approval at any time if, in the opinion of the Board, circumstances so warrant.

(2) This approval, unless rescinded before that date, expires on 31 December 2011 unless upon application by the Operator a later date is approved by the Board.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
Vice Chairman



SUNCOR PRIMROSE-CLEARWATER OIL SANDS PROJECT

ERCB

APPENDIX A TO APPROVAL NO. 4785

AREA OF CHANGE

REFERENCE

1. COMMERCIAL PROJECT DEVELOPMENT AREA
2. STAGE 1 DEVELOPMENT AREA

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

EXPLORATORY WELL PROPOSED BY SHELL
FOR JUTLAND (Castle River South) AREA

Memorandum of Decision
Procedures Meeting
Application 851037

1 INTRODUCTION

On 24 September 1985, the Energy Resources Conservation Board (Board) received an application from Shell Canada Resources Limited (Shell) for a licence to drill a well from a surface location in legal subdivision 2 of section 10, township 3, range 2, west of the 5th Meridian, to evaluate and obtain production from the Livingstone, Mount Head or Palliser formations. Shell had been in communication with certain public interest groups respecting the application and the Board had been advised by two of the groups that they had concerns respecting the proposed well and believed a public hearing of the application should take place. As a result, the Board arranged a meeting to discuss the procedures to be used in handling the application. The meeting was held in Calgary on 31 October 1985 and the following matters were discussed:

(a) the need for a hearing;

(b) the terms of reference of a public hearing, if one is held;

(c) the need for additional information or particulars to supplement or complete the application;

(d) the timing and availability of any additional information required;

(e) the appropriate timing of a public hearing, if one is held;

(f) the giving of notice of a public hearing, if one is held; and

(g) the availability of interveners' costs.

The panel members were G. J. DeSorcy, P.Eng., Panel Chairman, L. A. Bellows, P.Eng. and E. J. Morin, P.Eng.

The participants who registered at the meeting are shown in Appendix 1. Additionally, letters were received from the following who were not represented at the meeting:

- Mr. R. E. Wolf and Family, opposing the application.

- Alberta Fish and Game Association, indicating no opposition to the proposed test well at this time and that a hearing prior to having knowledge as to whether the well will be successful would not accomplish much.

The Federation of Alberta Naturalists also indicated an interest but was unable to attend the meeting.

2 NEED FOR HEARING

2.1 Views of Shell

Shell suggested that there was no need for a hearing of its application because:

- the necessary surface access had been obtained, subject to conditions, from the relevant Government body;
- none of the parties present at the meeting fit the description under section 29(2) of the Energy Resources Conservation Act which states:

  > "...if it appears to the Board that its decision on an application may directly and adversely affect the rights of a person, the Board shall give ...".

- the Crown, as owner and custodian of the public lands, related water bodies and wildlife, had agreed to the development and outside parties were not empowered to interfere.

Shell indicated that it had approached the Crown on several previous occasions but been denied access to the lands. The lands had, however, recently been re-zoned to a resource management category where controlled development may be permissible. Shell contended that the Crown, through the Department of Energy and Natural Resources, had already dealt with the concerns raised by the parties at the meeting and that there had been a public process. It argued that a hearing was not justified simply because certain groups disagreed with the policy decisions taken by the Crown.

Shell also contended that the Crown as owner, had jurisdiction over the management of public lands and wildlife, and since it had not specifically conferred that on the ERCB, the latter lacks jurisdiction to deal with those matters.

2.2 Views of AWA

The AWA contended that it represents members of the public who are users of the area in question and thus its members are persons that could be directly and adversely affected by the proposed well. It argued that the Crown merely held its interest in the lands in question in trust for the public.

The AWA stated that a Board hearing would be the only opportunity to review the impacts of the proposed activities on Crown lands, and that the Board had a few years ago, scheduled a public hearing in a similar situation because of AWA concerns.

The AWA suggested that Shell had not sufficiently recognized the uniqueness of the area and the related national, provincial, regional and international concerns.

2.3 Views of Wildlife Society

The Wildlife Society stated that it was very concerned with the potential impact of the well on wildlife, particularly the grizzly bear. It said that a Board hearing would be the only opportunity to deal with such concerns.

2.4 Views of Pincher Creek Association

The Pincher Creek Association stated that its members are farmers and ranchers with grazing leases in the general area. Also, as residents of the area, they were subject to potential health impacts from the proposed well. It therefore contended there was a need for a public hearing.

2.5 Views of Outfitters

Mr. Scott Miller, on behalf of Mr. Judd of the Outfitters, stated that the latter is licensed as a guide and outfitter in the region of the proposed well. He pointed out that as a resident of Beaver Mines, Mr. Judd lives as close to the site as anyone.

Argument on behalf of the Outfitters was that the Crown had alienated certain rights in the area to certain parties, including the Outfitters as well as Shell. This, coupled with the fact that Mr. Judd earned his living in the region of the well, qualified him as a person that could be directly and adversely affected by the proposed application. The Outfitters contended that a public hearing was necessary and that one should be scheduled.

2.6 Views of Parks Canada

Parks Canada indicated that it had a vested interest in the area and a concern regarding Shell's plan to drill a well. It stated however that it was not sure that a public forum was the best way to address its concerns.

2.7 Views of Board

The Board believes it must address two basic questions in determining whether a hearing of the subject application should be called. The first relates to the contention of Shell that the Board does not have jurisdiction respecting the management of public lands and the related water bodies and wildlife. The second is the question of whether any of the interested parties are potentially affected persons in terms of section 29 of the Energy Resources Conservation Act, and thus entitled to the guarantees of that section.

Respecting jurisdiction over public lands and wildlife, the Board does not accept Shell's position that the Board lacks jurisdiction because the Crown has not specifically conferred it on the Board. Section 3 of the Oil and Gas Conservation Act (the Act) provides that the Act applies to "every well situated in Alberta whenever drilled". The Board expects that, had the Crown intended to exempt public lands from the Board's jurisdiction, the Act and the many other statutes administered by the Board, would have specifically stated that exemption.

The Board acknowledges that broad policy decisions respecting the management of public lands and wildlife are the responsibility of the Crown, as owner. Nevertheless, the Board believes that the Act applies to the subject well and that, therefore, the Board has jurisdiction to consider the potential surface impacts of the subject well, including its potential impacts on wildlife. The views of the Board in this regard are considered further in section 3.7 of this Memorandum of Decision.

Regarding the matter of standing under section 29 of the Energy Resources Conservation Act, the Board has addressed the question first as it relates to the Outfitters and its owner Mr. Judd. The Board accepts the position argued by Mr. Scott Miller that Mr. Judd, as a licensed guide and outfitter in the region of the well and as an individual who earns his living in that manner, is a person whose rights may be directly and adversely affected by a decision respecting the subject application. Since Mr. Judd has requested a hearing, the Board is prepared to call one to consider the application.

Recognizing that a hearing will be scheduled as outlined above, the Board does not see the need at this time to rule on whether other interested groups are "persons" as referred to in section 29 of the Act who are guaranteed certain opportunities by the legislation. Since a hearing will take place, the Board will, subject to any procedural submissions and consequent rulings that may be made at the hearing, hear representations from any interested person, provided that the representations are limited to the terms of reference of the hearing. These terms of reference are considered in the following section of this Memorandum of Decision.

3 TERMS OF REFERENCE FOR HEARING

3.1 Views of Shell

Shell, although of the view that a hearing was not necessary, made certain suggestions respecting matters which should be dealt with if one takes place. It said the hearing should be limited to justification for the well, safety in the drilling of the well, and potential environmental impacts in the narrow sense and excluding wildlife.

Shell said that even though the drilling of a successful well could result in 4 to 6 additional wells and a pipeline to the Waterton plant, such potential future development should not be addressed at this time. Shell said that future applications would be necessary, and if the impacts were found unacceptable in the public interest, the Board could deny the applications as it had done on previous occasions. Shell stated that it would be totally at risk in that respect.

Shell said it would comply with all conditions imposed on it respecting its leasing arrangements with the Crown, including reclamation requirements and the limitation of public access. It also stated that any hearing should not be used to review earlier Government decisions respecting re-zoning of the lands in question or other policy matters.

3.2 Views of AWA

The AWA stated that the hearing should deal with the proposed well, its drilling, and resulting access to the area. It should also consider two possible future scenarios: one related to an unsuccessful well and its abandonment and the required reclamation; the other related to its success and follow-up developments.

The AWA also said the hearing should examine the total ecological unit, including provincial, federal and state matters, and having regard for social and cultural impacts as well as environmental effects.

3.3 Views of Wildlife Society

The Wildlife Society said that all environmental impacts, particularly on grizzly bears, must be reviewed.

3.4 Views of Pincher Creek Association

The Pincher Creek Association stated particular concern with the testing of the well. It also said that since Shell's seismic data indicated good chances of the well being successful, possible future developments should be looked at. These would include the pipeline to the Waterton plant and a possible extension to the life of the plant.

3.5 Views of Outfitters

The Outfitters expressed general agreement with the matters put forward by Shell with the specific exception that wildlife, economic impacts, and reclamation should be considered at the hearing. The Outfitters also stated that access to the area should be an issue.

Regarding the question of possible future developments, the Outfitters stated that the current application could not be considered in a vacuum and that the Board would have to have some regard for possible future development.

3.6 Views of Parks Canada

Parks Canada indicated that if there is a hearing it should deal with concerns respecting the environment, including wildlife. The question of monitoring impacts should also be dealt with.

3.7 Views of the Board

Clearly, the Board hearing is not for the purpose of reviewing the re-zoning decision made by the Government and the Board is not prepared to hear any evidence related to that matter.

The hearing will be for the purpose of considering the proposed Shell well and potential impacts of it. Having in mind that the well is exploratory in nature and there is great uncertainty as to whether it will encounter hydrocarbons, the Board is not prepared to consider impacts which might occur from possible future developments. Future applications would be needed for such developments and Shell would be at risk with respect to their approval or otherwise.

The Board will consider those matters which are within the Board's jurisdiction and relevant to the application. On the basis of the representations made at the meeting, the Board considers those matters to be:

- o the justification or need for the well,
- o safety precautions during drilling, and
- o impact on the environment of the drilling of the well at the proposed site and of the access road.

The environment, in the Board's judgement, includes wildlife. The Board thus is of the view that it has the jurisdiction to consider submissions as to the perceived impacts of the applied-for well on wildlife. The Board does not believe itself to have jurisdiction to address broad issues as to the present state and long-term management of wildlife in the area. Therefore, the Board emphasizes that it will consider only the impacts of the proposed drilling of the specific applied-for well, and does not intend to review long-term potential impacts of an on-going development which may or may not come to pass.

The Board would also be prepared to hear evidence regarding the extent of potential impacts of this single well on the Outfitters, not in respect of compensation but in considering the justification for the well.

The reclamation of the site, whether it occurs in the near future or in many years, is not within the jurisdiction of the Board and it is not prepared to hear detailed evidence in that regard. Its concern would be limited to being generally satisfied that successful reclamation could take place.

Further, the Board believes that it lacks jurisdiction to prescribe the location of the subject access road and the conditions relating to its construction, in light of section 14.1(3) of the Oil and Gas Conservation Act.

It is also important for the Board to emphasize that its jurisdiction is to deal only with the Alberta public interest. The Board has no intention of acting as a mediator between various jurisdictions and will limit its examination to evidence related specifically to Alberta.

4 NEED FOR ADDITIONAL INFORMATION

4.1 Views of Shell

Shell indicated that it would file details of its leasing arrangements with the Crown. It argued against the need for a detailed environmental impact assessment but indicated it would respond to any deficencies identified by the Board.

Shell stated that the drilling plan and emergency response plan could both be reviewed by the Board without the holding of a public hearing.

4.2 Views of Other Participants

The AWA presented a detailed list of additional information it believed essential to the examination of the Shell application. It included an assessment of the environment, including possible impacts, monitoring and mitigation. It also dealt with cultural resources, economic and social impacts, impacts resulting from access to the area, and geological data.

Others generally supported the need for detailed environmental information with the Wildlife Society and Parks Canada emphasizing the need for detailed information related to wildlife. The Outfitters specifically requested information regarding the expected H_2S content and safety measures in that respect.

4.3 Views of Board

The Board, as indicated in the previous section, will concern itself only with the potential impact of the specific well proposed by Shell and the related access road. It will thus not direct the filing of detailed environmental studies, including those of a field observation variety suggested by several potential interveners.

Since the proposal is to drill a well in accordance with certain conditions attached to the surface lease, the listing of those conditions will be required. The following additional information will also be required of Shell:

- the drilling plan;
- the emergency response plan including a discussion of the maximum potential release rate for hydrogen sulphide; and
- a general assessment of impacts on the environment which might result from the proposed well and access road and any mitigative measures which will be taken.

5 TIMING OF AVAILABILITY OF ADDITIONAL INFORMATION AND OF THE HEARING

5.1 Views of Participants

Shell indicated that it could have general environmental information available in about one week but that the detailed report being requested by others could not be completed for a year or more. It suggested, if a hearing was necessary, it should take place by mid December.

The other participants in the meeting generally indicated that it would take three to six months to prepare for a hearing.

5.2 Views of Board

The Board does not agree with many of the participants that a delay of three months or more is necessary prior to convening a hearing. This is primarily because the scope of the hearing will be much narrower than suggested by the same parties.

The Board believes the additional information requested of Shell can be filed not later than 25 November, 1985. Assuming this to be the case, the Board is scheduling the hearing of the application for the 6th of January 1986 in Calgary. Interveners' submissions will be required by the 27 December 1985.

The Board will give notice of the hearing to those who attended the meeting and additionally will publish the notice in the Calgary, Edmonton and Pincher Creek papers.

6 INTERVENERS' COSTS

Shell stated at the meeting that it was giving notice that it did not believe those parties in attendance at the meeting qualified for interveners' costs. Mr. Scott Miller, on behalf of the Outfitters, indicated a belief that his client does qualify and suggested a meeting prior to any hearing to determine the status of persons for purposes of interveners' costs. Shell indicated no disagreement with such a meeting.

The Board agrees that a meeting to discuss the status of interveners with respect to costs would be useful. It will arrange such a meeting to take place a few days following the filing of the additional information by Shell. It will notify those who participated in the October 31 meeting of the details for the interveners' costs status meeting when they are finalized.

ISSUED at Calgary, Alberta, on 14 November 1985.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy
G. J. DeSorcy
Vice Chairman

L. A. Bellows
Board Member

E. J. Morin
Acting Board Member

APPENDIX 1

THOSE WHO APPEARED AT THE MEETING

Participants	Representatives
Shell Canada Resources Limited (Shell)	Mr. K. R. Miller Mr. J. R. Tilbe
Alberta Wilderness Association (AWA)	Mrs. V. Pharis Ms. D. Pachal
The Wildlife Society of Canada (Wildlife Society)	Ms. R. Usher Mr. J. Kansas
Pincher Creek Area Environmental Association (Pincher Creek Association)	Mrs. S. Taylor
Diamond Hitch Outfitters (Outfitters)	Mr. S. R. Miller
Parks Canada: Waterton Lakes National Park (Parks Canada)	Mr. B. Lieff Dr. B. Leeson
Energy Resources Conservation Board staff (Board Staff)	Ms. A. Gervais Mr. E. R. Brushett, P.Eng. Mr. F. Sorenson Mr. R. Paulson